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FPSC - COMMISSION CLERK

Docket No. 160001-EI
Comprehensive Exhibit List for Entry into Hearing Record
November 2, 2016

EXH #	Witness	I.D. # As Filed	Exhibit Description	Issue Nos.	Entered
STAFF					
1		Exhibit List	Comprehensive Exhibit List		
DUKE ENERGY FLORIDA, LLC – (DIRECT)					
2	Christopher A. Menendez	CAM-1T	Fuel Cost Recovery True-Up (Jan – Dec. 2015)	2C, 7-12, 19-23, 24A, 28-37	**stipulated**
3	Christopher A. Menendez	CAM-2T	Capacity Cost Recovery True Up (Jan – Dec. 2015)	2C, 7-12, 19-23, 24A, 28-37	**stipulated**
4	Christopher A. Menendez	CAM-3T	Schedules A1 through A3, A6 and A12 for Dec 2015	2C, 7-12, 19-23, 24A, 28-37	**stipulated**
5	Christopher A. Menendez	CAM-4T	2015 Capital Structure and Cost Rates Applied to Capital Projects	2C, 7-12, 19-23, 24A, 28-37	**stipulated**
6	Christopher A. Menendez	CAM-2	Actual/Estimated true-up Schedules for period January – December 2016 (**Confidential DN 05863-16**)	2C, 7-12, 19-23, 24A, 28-37	**stipulated**
7	Christopher A. Menendez	CAM-3	Projection factors for January to December 2017 (**Confidential DN 07222-16**)	2C, 7-12, 19-23, 24A, 28-37	**stipulated**
8	Joseph McCallister	JM-1T	Hedging True-Up August through December 2015 (**Confidential DN 01837-16**)	1A, 1B, 2A, 2B	**stipulated**
9	Joseph McCallister	JM-2T	Hedging Monthly Projected light oil burns (**Confidential DN 01837-16**)	1A, 1B, 2A, 2B	**stipulated**
10	Joseph McCallister	JM-1P	2017 Risk Management Plan (**Confidential DN 05867-16**)	1A, 1B, 2A, 2B	**stipulated**

11	Joseph McCallister	JM-2P	Hedging Report (January – July 2016) (**Confidential DN 06830-16**)	1A, 1B, 2A, 2B	**stipulated**
12	Matthew J. Jones	MJJ-1T	GPIF Reward/Penalty Schedules for 2015	17, 18	**stipulated**
13	Matthew J. Jones	MJJ-1P	GPIF Targets/Ranges Schedules (for Jan – Dec. 2017)	17, 18	**stipulated**
14	Marcia Olivier	MO-1	Projection factors for January to December 2017– ISFSI	24B, 32	**stipulated**
15	Marcia Olivier	MO-2	Projection factors for January to December 2017 – Batch 19 Fuel Sale (**Confidential DN 07222-16**)	24B, 32	**stipulated**
16	Marcia Olivier	MO-3	Projection factors for January to December 2017– RRSSA Second Amendment (**Confidential DN 07222-16**)	24B, 32	**stipulated**
17	Marcia Olivier	CAM-3	Co-sponsoring Schedule E12-A, Page 1 of 2: Lines 26, 27, and 38 (**Confidential DN 07222-16**)	24B, 32	**stipulated**
FLORIDA POWER & LIGHT COMPANY – (DIRECT & SUPPLEMENTAL) ***Notice of Adoption of Terry J. Keith's testimony and exhibits by Renae B. Deaton, filed on October 3, 2016, (FPSC DN #07930-16).***					
18	*R. B. Deaton	TJK-1	Fuel Cost Recovery 2015 Final True Up Calculation	3J, 7-12, 19-23, 25, 28-37	**stipulated**
19	*R. B. Deaton	TJK-2	Capacity Cost Recovery 2015 Final True Up Calculation (**Confidential DN 01144-16**)	3J, 7-12, 19-23, 25, 28-37	**stipulated**
20	*R. B. Deaton	TJK-3	FCR 2016 Actual/Estimated True Up Calculation	3J, 7-12, 19-23, 25, 28-37	**stipulated**
21	*R. B. Deaton	TJK-4	CCR 2016 Actual/Estimated True Up Calculation	3J, 7-12, 19-23, 25, 28-37	**stipulated**
22	*R. B. Deaton	TJK-5	FCR 2017 E-Schedules Jan through Dec 2017	3J, 7-12, 19-23, 25, 28-37	**stipulated**

23	*R. B. Deaton	TJK-6	CCR 2017 E-Schedules Jan through Dec 2017 Proposed Cost Allocation Methodology 12 CP and 25% (**Confidential DN 07226-16**)	3J, 7-12, 19-23, 25, 28-37	**stipulated**
24	*R. B. Deaton	TJK-7	CCR 2017 E-Schedules Jan through Dec 2017 Current Cost Allocation Methodology 12 CP and 1/13th	3J, 7-12, 19-23, 25, 28-37	**stipulated**
25	*R. B. Deaton	TJK-8	2017 Revenue Requirement Calculation for West County Energy Center Unit 3	3J, 7-12, 19-23, 25, 28-37	**stipulated**
26	G. J. Yupp	GJY-1	2015 Incentive Mechanism Results (**Confidential DN 01144-16**)	1A, 1B, 3A-3I, 3K, 9-12, 19	**stipulated**
27	G. J. Yupp	GJY-2	August 2015 through December 2015 Hedging Activity True-up Report (**Confidential DN 01842-16**)	1A, 1B, 3A-3I, 3K, 9-12, 19	**stipulated**
28	G. J. Yupp	GJY-3	Woodford Refund Calculation	1A, 1B, 3A-3I, 3K, 9-12, 19	**stipulated**
29	G. J. Yupp	GJY-4	VOM Correction Refund	1A, 1B, 3A-3I, 3K, 9-12, 19	**stipulated**
30	G. J. Yupp	GJY-5	FCR 2017 Risk Management Plan (**Confidential DN 05880-16**)	1A, 1B, 3A-3I, 3K, 9-12, 19	**stipulated**
31	G. J. Yupp	GJY-6	Hedging Activity Report (**Confidential DN 06844-16**)	1A, 1B, 3A-3I, 3K, 9-12, 19	**stipulated**
32	G. J. Yupp	GJY-7	Fuel Cost Recovery Forecast Assumptions	1A, 1B, 3A-3I, 3K, 9-12, 19	**stipulated**
33	G. J. Yupp	GJY-8	Alternative 2017 Risk Management Plan	1A, 1B, 3A-3I, 3K, 9-12, 19	**stipulated**
34	C. R. Rote	CRR-1	Generating Performance Incentive Factor Performance Results for January 2015 through December 2015	17-18	**stipulated**
35	C. R. Rote	CRR-2	Generating Performance Incentive Factor Performance Targets for January 2017 through December 2017	17-18	**stipulated**

FLORIDA PUBLIC UTILITIES COMPANY – (DIRECT)					
36	Curtis D. Young	CDY-1	Final True Up Schedules (Schedules A, C1 and E1-B for FPUC's Divisions)	9	**stipulated**
37	Michael Cassel	MC-1	Estimated/Actual (Schedules El-A, El-B, and El-B1)	10-12, 19-23, 35	**stipulated**
38	Michael Cassel	MC-2	Schedules E1, E1A, E2, E7, E8, E10 and Schedule A (**Confidential DN 07262-16**)	10-12, 19-23, 35	**stipulated**
GULF POWER COMPANY – (DIRECT)					
39	H. R. Ball	HRB-1	Coal Suppliers, Natural Gas Price Variance, Hedging Effectiveness	1A, 5A, 5B, 7, 8, 28, 31, 32	**stipulated**
40	H. R. Ball	HRB-2	Projected vs. Actual Fuel Cost of System Generation Comparison 2006 - 2017	1A, 5A, 5B, 7, 8, 28, 31, 32	**stipulated**
41	H. R. Ball	HRB-3	Hedging Information Report August – December 2015 (**Confidential DN 01826-16**)	1A, 5A, 5B, 7, 8, 28, 31, 32	**stipulated**
42	H. R. Ball	HRB-4	Hedging Information Report January – July 2016 (**Confidential DN 06820-16**)	1A, 5A, 5B, 7, 8, 28, 31, 32	**stipulated**
43	H. R. Ball	HRB-5	Risk Management Plan for Fuel Procurement for 2017 (**Confidential DN 05871-16**)	1A, 5A, 5B, 7, 8, 28, 31, 32	**stipulated**
44	C. S. Boyett	CSB-1	Calculation of Final True-Up and A-Schedules January 2015 – December 2015 (**Confidential DN 01131-16**)	7, 8, 9, 10, 11, 12, 19, 20, 21, 22, 23, 28, 29, 30, 31, 32, 33, 34, 35, 36	**stipulated**
45	C. S. Boyett	CSB-2	Estimated True-Up January 2016 – December 2016 (**Confidential DN 05869-16**)	7, 8, 9, 10, 11, 12, 19, 20, 21, 22, 23, 28, 29, 30, 31, 32, 33, 34, 35, 36	**stipulated**
46	C. S. Boyett	CSB-3	Projection January 2017 – December 2017 (**Confidential DN 07228-16**)	7, 8, 9, 10, 11, 12, 19, 20, 21, 22, 23, 28, 29, 30, 31, 32, 33, 34, 35, 36	**stipulated**

47	C. L. Nicholson	CLN-1	Gulf Power Company GPIF Results January 2015 – December 2015	17-18	**stipulated**
48	C. L. Nicholson	CLN-2	Gulf Power Company GPIF Targets and Ranges January 2017 – December 2017	17-18	**stipulated**
TAMPA ELECTRIC COMPANY – (DIRECT)					
49	Penelope A. Rusk	PAR-1	Final True-up Capacity Cost Recovery January 2015 – December 2015 Final True-up Fuel Cost Recovery January 2015- December 2015 Actual Fuel True-up Compared to Original Estimates January 2015 – December 2015 Schedules A-1, A-2 and A-6 through A-9 and A-12 January 2015 – December 2015 (**Confidential DN 01124-16**) Capital Projects approved for Fuel Clause Recovery January 2015 – December 2015	7, 8, 9, 10, 11, 12, 19, 20, 21, 22, 23, 28, 29, 30, 31, 32, 33, 34, 35, 36, 37	**stipulated**

50	Penelope A. Rusk	PAR-2	Actual/Estimated True-Up Fuel Cost Recovery January 2016 – December 2016 Actual/Estimated True-Up Capacity Cost Recovery January 2016 – December 2016 (**Confidential DN 05890-16**) Capital Projects Approved for Fuel Clause Recovery January 2016 – December 2016	7, 8, 9, 10, 11, 12, 19, 20, 21, 22, 23, 28, 29, 30, 31, 32, 33, 34, 35, 36, 37	**stipulated**
51	Penelope A. Rusk	PAR-3	Projected Capacity Cost Recovery January 2017 – December 2017 (**Confidential DN 07260-16**) Projected Fuel Cost Recovery January 2017 – December 2017 Levelized and Tiered Fuel Rate January 2017 – December 2017 Capital Projects Approved for Fuel Clause Recovery January 2017 – December 2017	7, 8, 9, 10, 11, 12, 19, 20, 21, 22, 23, 28, 29, 30, 31, 32, 33, 34, 35, 36, 37	**stipulated**
52	Brian S. Buckley	BSB-1	Final True-Up Generating Performance Incentive Factor January 2015 – December 2015 Actual Unit Performance Data January 2015 – December 2015	17-18	**stipulated**
53	Brian S. Buckley	BSB-2	Generating Performance Incentive Factor January 2017 – December 2017 Summary of Generating Performance Incentive Factor Targets January 2017 – December 2017	17-18, 19	**stipulated**
54	J. Brent Caldwell	JBC-1	Final True-Up Hedging Activity Report January 2015 – December 2015 (**Confidential DN 01830-16**)	1A, 1B, 6A, 6B, 19	**stipulated**

55	J. Brent Caldwell	JBC-2	Risk Management Plan January 2017 – December 2017 (**Confidential DN 05887-16**)	1A, 1B, 6A, 6B, 19	**stipulated**
56	J. Brent Caldwell	JBC-3	Natural Gas Hedging Report January 2016 – July 2016 (**Confidential DN 06818-16**)	1A, 1B, 6A, 6B, 19	**stipulated**
OFFICE OF PUBLIC COUNSEL – (DIRECT)					
57	Tarik Noriega	TN-1	Résumé of Tarik Noriega	1A, 1B (Hedging Issues)	**stipulated**
58	Tarik Noriega	TN-2	IOU Natural Gas Hedging Gains/(Losses) From 2002-2015	1A, 1B (Hedging Issues)	**stipulated**
59	Tarik Noriega	TN-3	IOU Discovery Responses	1A, 1B (Hedging Issues)	**stipulated**
60	Daniel J. Lawton	DJL-1	Resume of Daniel J. Lawton	1A, 1B (Hedging Issues)	**stipulated**
61	Daniel J. Lawton	DJL-2	Testimony & Exhibits of Danie1 J. Lawton filed in Docket No. 150001-EI	1A, 1B (Hedging Issues)	**stipulated**
62	Daniel J. Lawton	DJL-3	Monthly Henry Hub Spot Prices $/MMBT	1A, 1B (Hedging Issues)	**stipulated**
63	Daniel J. Lawton	DJL-4	Hedging Gains & Losses Summary (2002-2016)	1A, 1B (Hedging Issues)	**stipulated**
64	Daniel J. Lawton	DJL-5	Excerpt From Dewhurst Deposition	1A, 1B (Hedging Issues)	**stipulated**
65	Daniel J. Lawton	DJL-6	FPL Witness Yupp's 2015 Analysis of Hedging Volatility Reduction Benefits	1A, 1B (Hedging Issues)	**stipulated**
66	Daniel J. Lawton	DJL-7	Alternative Non-Hedging Fuel Factor	1A, 1B (Hedging Issues)	**stipulated**
STAFF – (DIRECT)					
67	Simon O. Ojada	SOO-1	Staff Audit Report For Hedging Activities – DEF	2A	**stipulated**

68	Iliana H. Piedra (Marissa N. Glover)	MNG-1	Staff Audit Report For Hedging Activities - FPL	3A	**stipulated**
69	George Simmons (Donna D. Brown)	DDB-1	Staff Audit Report For Hedging Activities – GPC	5A	**stipulated**
70	Intesar Terkerkawi	IT-1	Staff Audit Report For Hedging Activities – TEC	6A	**stipulated**
71	Michael A. Gettings	MAG-1	Curriculum Vitae of Michael A. Gettings	1A, 1B, 2B, 3B, 5B, 6B	**stipulated**
72	Michael A. Gettings	MAG-2	Sample Quarterly Risk Report	1A, 1B, 2B, 3B, 5B, 6B	**stipulated**
73	Michael A. Gettings	MAG-3	Glossary of Terms	1A, 1B, 2B, 3B, 5B, 6B	**stipulated**
74	Mark Anthony Cicchetti	MAC-1	Curriculum Vitae of Mark Anthony Cicchetti	1A, 1B, 2B, 3B, 5B, 6B	**stipulated**
75	Mark Anthony Cicchetti	MAC-2	Henry Hub Spot Price (January, 1997 through August, 2016)	1A, 1B, 2B, 3B, 5B, 6B	**stipulated**
76	Mark Anthony Cicchetti	MAC-3	Proposed Resolution of Issues (from Order No. PSC-02-1484-FOF-EI)	1A, 1B, 2B, 3B, 5B, 6B	**stipulated**
77	Mark Anthony Cicchetti	MAC-4	Utility Hedging Practices summary	1A, 1B, 2B, 3B, 5B, 6B	**stipulated**
78	Mark Anthony Cicchetti	MAC-5	Hedging Under Scrutiny article	1A, 1B, 2B, 3B, 5B, 6B	**stipulated**
79	Matthew J. Jones		DEF's Response to Staff's Second Set of Interrogatories, Nos. 9-11. *[Bates Nos. 00001-00005]*	17	**stipulated**
80	Joseph McCallister		DEF's Response to Staff's Fourth Set of Interrogatories, No. 15 (Redacted). *[Bates Nos. 00006-00009]*	1A, 1B, 2B	**stipulated**
81	Joseph McCallister		DEF's Response to Staff's Fourth Set of Interrogatories, No. 15 (**Confidential DN 07080-16**). *[Bates No. 00010]*	1A, 1B, 2B	**stipulated**

82	Joseph McCallister		DEF's Response to Staff's Amended Fifth Set of Interrogatories, Nos. 16-23. *[Bates Nos. 00011-00022]*	2B	**stipulated**
83	Joseph McCallister		DEF's Response to Staff's Sixth Set of Interrogatories, Nos. 24-27 (Redacted), 28-30. *[Bates Nos. 00023-00052]*	2A	**stipulated**
84	Joseph McCallister		DEF's Response to Staff's Sixth Set of Interrogatories, Nos. 24-27 (**Confidential DN 07860-16**). *[Bates No. 00053]*	2A	**stipulated**
85	Marcia Olivier		DEF's Response to Staff's Seventh Set of Interrogatories, No. 31. *[Bates Nos. 00054-00058]*	24B	**stipulated**
86	Gerard J. Yupp		FPL's Response to Staff's First Set of Interrogatories, Nos. 12 (Redacted), 13, 14, 24 and 25 (Redacted). *[Bates Nos. 00059-00069]*	3C, 3D and 3E (items 12-14 and 24-25)	**stipulated**
87	Gerard J. Yupp		FPL's Response to Staff's First Set of Interrogatories, Nos. 12 and 25 (**Confidential DN 02405-16**). *[Bates No. 00070]*	3C, 3D and 3E	**stipulated**
88	Charles R. Rote		FPL's Response to Staff's Second Set of Interrogatories, Nos. 26-29. *[Bates Nos. 00071-00078]*	17	**stipulated**
89	Gerard J. Yupp		FPL's Response to Staff's Fourth Set of Interrogatories, No. 41 (Redacted). *[Bates Nos. 00079-00081]*	1A, 1B, 3B	**stipulated**
90	Gerard J. Yupp		FPL's Response to Staff's Fourth Set of Interrogatories, No. 41(**Confidential DN 07038-16**). *[Bates No. 00082]*	1A, 1B, 3B	**stipulated**
91	Gerard J. Yupp		FPL's Response to Staff's Fifth Set of Interrogatories, Nos. 42-49. *[Bates Nos. 00083-00092]*	3B	**stipulated**

92	Gerard J. Yupp		FPL's Response to Staff's Sixth Set of Interrogatories, Nos. 50 (Redacted), 51-55. *[Bates Nos. 00093-00107]*	3A	**stipulated**
93	Gerard J. Yupp		FPL's Response to Staff's Sixth Set of Interrogatories, No. 50 (**Confidential DN 07867-16**). *[Bates No. 00108]*	3A	**stipulated**
94	Gerard J. Yupp		FPL's Response to OPC's Second Request for Production of Document, No. 3. *[Bates Nos. 00109-00122]*	3K	**stipulated**
95	Susan D. Ritenour (signed the affidavit) Cody Nicholson testifies about Issue 17)		Gulf's Response to Staff's Second Set of Interrogatories, Nos. 11-14. *[Bates Nos. 00123-00129]*	17	**stipulated**
96	Susan D. Ritenour (signed the affidavit) H.R. Ball testifies about Issues 1A, 1B, and 5B)		Gulf's Response to Staff's Third Set of Interrogatories, No. 15. *[Bates Nos. 00130-00133]*	1A, 1B, 5B	**stipulated**
97	Susan D. Ritenour (signed the affidavit) H.R. Ball testifies about Issues 1A, 1B, and 5B)		Gulf's Response to Staff's Fourth Set of Interrogatories, Nos. 16-23. *[Bates Nos. 00134-00144]*	5B	**stipulated**
98	Susan D. Ritenour (signed the affidavit) H.R. Ball testifies about Issues 1A, 1B, and 5B)		Gulf's Response to Staff's Fifth Set of Interrogatories, Nos. 24-29. *[Bates Nos. 00145-00158]*	5A	**stipulated**
99	Penelope A. Rusk		TECO's Response to Staff's Second Set of Interrogatories, Nos. 12-14. *[Bates Nos. 00159-00165]*	17	**stipulated**
100	Penelope A. Rusk		TECO's Response to Staff's Fourth Set of Interrogatories, No. 17 (Redacted). *[Bates Nos. 00166-00171]*	1A, 1B, 6B	**stipulated**

101	Penelope A. Rusk		TECO's Response to Staff's Fourth Set of Interrogatories, No. 17 (**Confidential DN 07105-16**). *[Bates No. 00172]*	1A, 1B, 6B	**stipulated**
102	Penelope A. Rusk		TECO's Response to Staff's Fifth Set of Interrogatories, Nos. 18, 19 (Redacted), 20-24, 25-27 (Redacted), 28. *[Bates Nos. 00173-00193]*	6B	**stipulated**
103	Penelope A. Rusk		TECO's Response to Staff's Fifth Set of Interrogatories, Nos. 19, 25-27 (**Confidential DN 07257-16**). *[Bates No. 00194]*	6B	**stipulated**
104	Penelope A. Rusk		TECO's Response to Staff's Sixth Set of Interrogatories, Nos. 29 (Redacted), 30-34. *[Bates Nos. 00195-00210]*	6A	**stipulated**
105	Penelope A. Rusk		TECO's Response to Staff's Sixth Set of Interrogatories, No. 29 (**Confidential DN 07882-16**). *[Bates No. 00211]*	6A	**stipulated**
106	Penelope A. Rusk		TECO's Response to Staff's Seventh Set of Interrogatories, No. 35 (Redacted). *[Bates Nos. 00212-00217]*	1A, 1B, 6B	**stipulated**
107	Penelope A. Rusk		TECO's Response to Staff's Seventh Set of Interrogatories, No. 35 (**Confidential DN 08025-16**). *[Bates No. 00218]*	1A, 1B, 6B	**stipulated**
108	Penelope A. Rusk		TECO's Response to Staff's Eighth Set of Interrogatories, No. 36. *[Bates Nos. 00219-00226]*	12	**stipulated**
109	R.B. Deaton		Joint Motion For Approval of Settlement Agreement, filed on October 6, 2016 in Docket Nos. 160021-EI, 160061-EI, 160062-EI and 160088-EI. *[Bates Nos. 00227-00480]*	3J, 7-12, 19-23, 25, 28-37	**stipulated**

110	Joseph McCallister H.R. Ball Penelope Rusk		Joint Stipulation and Agreement for Interim Resolution of Hedging Issues, filed on October 24, 2016 in Docket No. 160001-EI. *[Bates Nos. 00481-00493]*	1A, 1B (All petitioners), 2B, 5B, 6B	**stipulated**
111	Gerard J. Yupp		FPL's Adoption of Hedging Stipulation, filed on October 24, 2016 in Docket No. 160001-EI. *[Bates Nos. 00494-00497]*	1A, 1B, 3B	**stipulated**
112	Christopher A. Menendez		DEF's Response to PCS' First Set of Interrogatories, No. 1. *[Bates Nos. 00498-00501]*	1A, 1B, 2B	**stipulated**
113	Joseph McCallister		DEF's Response to OPC's Second Set of Interrogatories, Nos. 11, 12-13 (Redacted), 14, 15, 16 (Redacted), 17, 18. *[Bates Nos. 00502-00513]*	1A, 1B, 2B	**stipulated**
114	Joseph McCallister		DEF's Response to OPC's Second Set of Interrogatories, Nos. 12-13, 16 (**Confidential DN 06926-16**). *[Bates No. 00514]*	1A, 1B, 2B	**stipulated**

HEARING EXHIBITS

Live Exhibit Number	Witness	Party	Description		Moved In/Due Date of Late Filed
115	Christopher A. Menendez	Staff	PCS Phosphate's First Set of Interrogatories to DEF, No. 1, including excel file Attachment PCS-Axlsx		**stipulated**

Duke Energy Florida
Fuel Adjustment Clause
Summary of Actual True-Up Amount
January through December 2015

Line No.	Description	Contribution to Over/(Under) Recovery Period to Date
	KWH Sales:	
1	Jurisdictional Kwh sales - difference	767,592,894
2	Non-Jurisdictional Kwh sales - difference	118,705,542
3	Total System Kwh sales - difference Schedule A2, pg 1 of 2, line B3	886,298,436
	System:	
4	Fuel and Net Purchased Power Costs - difference Schedule A2, page 2 of 2, line C4	$ (38,537,149)
	Jurisdictional:	
5	Fuel Revenues - difference Schedule A2, page 2 of 2, line C3	$ 60,315,187
6	Fuel and Net Purchased Power Costs - difference Schedule A2, page 2 of 2, line C6 - C12 - C7	(44,625,243)
7	True Up amount for the period	104,940,430
8	True Up for the prior period Schedule A2, page 2 of 2, lines C9 + C10	11,604,968
9	Interest Provision Schedule A2, page 2 of 2, line C8	17,682
10	Actual True Up ending balance for the period January 2015 through December 2015 Schedule A2, page 2 of 2, line C13	116,563,080
11	Estimated True Up ending balance for the period included in the filing of Levelized Fuel Cost Factors January through December 2015, Docket No. 150001-EI.	78,731,031
12	Total True Up for the period January 2015 through December 2015	$ 37,832,048

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 2
PARTY: DUKE ENERGY FLORIDA, LLC – (DIRECT)
DESCRIPTION: Christopher A. Menendez CAM-1T

Duke Energy Florida
Calculation of Actual True-up
For the Period of January through December 2015

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 100,097,800	$ 97,550,693	$ 103,349,547	$ 112,810,811	$ 128,846,041	$ 134,240,962	$ 676,895,855
	2	Fuel Cost of Power Sold	(3,943,219)	(3,521,334)	(2,126,058)	(2,598,022)	(5,784,393)	(5,380,107)	(23,353,133)
	3	Fuel Cost of Purchased Power	7,520,849	7,910,824	10,237,409	14,882,323	12,928,988	24,457,418	77,937,812
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	8,990,368	8,182,122	8,070,423	9,132,303	10,888,108	10,001,969	55,265,293
	4	Energy Cost of Economy Purchases	452,250	582,968	600,426	654,836	460,058	420,572	3,171,110
	5	Adjustments to Fuel Cost	(14,256)	(21,380)	(143,979)	(17,701)	(17,248)	(16,864)	(231,427)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	113,103,792	110,683,892	119,987,769	134,864,551	147,321,554	163,723,951	789,685,509
B	1	Jurisdictional MWH Sales	2,654,267	2,638,626	2,812,088	2,933,622	3,114,914	3,580,025	17,733,543
	2	Non-Jurisdictional MWH Sales	30,765	17,672	21,095	27,293	40,872	40,062	177,760
	3	TOTAL SALES (Lines B1 + B2)	2,685,032	2,656,299	2,833,182	2,960,916	3,155,787	3,620,087	17,911,302
	4	Jurisdictional % of Total Sales (Line B1/B3)	98.85%	99.33%	99.26%	99.08%	98.70%	98.89%	99.01%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	119,677,266	119,280,708	127,253,695	133,158,428	142,927,573	165,551,705	807,849,374
	1a	RRSSA Refund - $40M	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	20,000,000
	1b	RRSSA Fuel Adjustment	(2,654,267)	(2,638,626)	(2,812,088)	(2,933,622)	(3,114,914)	(3,580,025)	(17,733,542)
	1c	RRSSA Refund - $10M	833,333	833,333	833,333	833,333	833,333	833,333	5,000,000
	2	True-Up Provision	(6,139,350)	(6,139,350)	(6,139,350)	(6,139,350)	(6,139,350)	(6,139,350)	(36,836,102)
	2a	Incentive Provision	(185,988)	(185,988)	(185,988)	(185,988)	(185,988)	(185,988)	(1,115,927)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	114,864,327	114,483,410	122,282,936	128,066,135	137,653,987	159,813,009	777,163,803
	4	Fuel & Net Power Transactions (Line A6)	113,103,792	110,683,892	119,987,769	134,864,551	147,321,554	163,723,951	789,685,509
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	111,968,567	110,105,025	119,161,791	133,693,281	145,481,985	161,990,807	782,401,456
	6	Over/(Under) Recovery (Line 3 - Line 5)	2,895,760	4,378,385	3,121,145	(5,627,147)	(7,827,998)	(2,177,798)	(5,237,653)
	7	Interest Provision	(4,604)	(3,822)	(3,031)	(1,981)	(2,352)	(2,597)	(18,387)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	2,891,156	4,374,563	3,118,113	(5,629,127)	(7,830,350)	(2,180,395)	(5,256,040)
	9	Plus: Prior Period Balance	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)
	10	Plus: Cumulative True-Up Provision	6,139,350	12,278,701	18,418,051	24,557,401	30,696,751	36,836,102	36,836,102
	11	Subtotal Prior Period True-up	(55,927,885)	(49,788,535)	(43,649,184)	(37,509,834)	(31,370,484)	(25,231,134)	(25,231,134)
	12	Regulatory Accounting Adjustment	0	0	0	0	0	0	-
	13	TOTAL TRUE-UP BALANCE	($53,036,729)	(42,522,815)	($33,265,352)	($32,755,129)	($34,446,129)	($30,487,175)	($30,487,175)

Duke Energy Florida
Calculation of Actual True-up
For the Period of January through December 2015

			JUL ACTUAL	AUG ACTUAL	SEPT ACTUAL	OCT ACTUAL	NOV ACTUAL	DEC ACTUAL	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 134,971,906	$ 136,167,259	$ 123,877,804	$ 102,877,886	$ 86,223,146	$ 87,562,430	$ 1,348,576,285
	2	Fuel Cost of Power Sold	(3,741,183)	(4,611,863)	(2,407,645)	(1,960,420)	(2,093,316)	(521,220)	(38,688,780)
	3	Fuel Cost of Purchased Power	15,685,752	18,818,065	14,688,043	18,882,967	19,496,193	7,720,621	173,229,452
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	10,765,678	11,400,036	10,608,406	8,805,289	10,236,627	10,642,495	117,723,823
	4	Energy Cost of Economy Purchases	738,688	(143,040)	294,192	529,139	687,147	101,778	5,379,013
	5	Adjustments to Fuel Cost	2,166,175	(16,699)	(19,357)	(16,722)	(10,706)	(18,543)	1,852,721
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	160,587,015	161,613,758	147,041,443	129,118,138	114,539,090	105,487,560	1,608,072,513
B	1	Jurisdictional MWH Sales	3,728,754	3,837,385	3,761,238	3,282,016	3,354,008	2,856,238	38,553,182
	2	Non-Jurisdictional MWH Sales	34,255	40,897	33,220	29,891	23,549	18,555	358,127
	3	TOTAL SALES (Lines B1 + B2)	3,763,010	3,878,282	3,794,458	3,311,907	3,377,557	2,874,793	38,911,308
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.09%	98.95%	99.12%	99.10%	99.30%	99.35%	99.08%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	173,664,390	177,869,035	174,482,205	151,101,290	153,223,661	125,316,286	1,763,506,241
	1a	RRSSA Refund - $40M	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	40,000,000
	1b	RRSSA Fuel Adjustment	(3,728,755)	(3,837,000)	(3,761,622)	(3,282,016)	(3,354,007)	(2,856,240)	(38,553,183)
	1c	RRSSA Refund - $10M	833,333	833,333	833,333	833,333	833,333	833,333	10,000,000
	2	True-Up Provision	(6,139,350)	(6,139,350)	(6,139,350)	(6,139,350)	(6,139,350)	(6,139,350)	(73,672,203)
	2a	Incentive Provision	(185,988)	(185,988)	(185,988)	(185,988)	(185,988)	(185,988)	(2,231,853)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	167,776,964	171,873,363	168,561,912	145,660,602	147,710,983	120,301,375	1,699,049,002
	4	Fuel & Net Power Transactions (Line A6)	160,587,015	161,613,758	147,041,443	129,118,138	114,539,090	105,487,560	1,608,072,513
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	159,208,419	159,999,971	145,823,266	128,022,612	113,796,460	104,856,388	1,594,108,572
	6	Over/(Under) Recovery (Line 3 - Line 5)	8,568,545	11,873,393	22,738,645	17,637,991	33,914,523	15,444,986	104,940,429
	7	Interest Provision	(1,851)	(610)	1,667	4,300	8,241	24,322	17,683
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	8,566,694	11,872,783	22,740,312	17,642,291	33,922,764	15,469,308	104,958,112
	9	Plus: Prior Period Balance	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)
	10	Plus: Cumulative True-Up Provision	42,975,452	49,114,802	55,254,152	61,393,503	67,532,853	73,672,203	73,672,203
	11	Subtotal Prior Period True-up	(19,091,783)	(12,952,433)	(6,813,083)	(673,733)	5,465,618	11,604,968	11,604,968
	12	Regulatory Accounting Adjustment	0	0	0	0	0	0	-
	13	TOTAL TRUE-UP BALANCE	($15,781,130)	$2,231,003	$31,110,666	$54,892,307	$94,954,421	$116,563,080	$116,563,080

Duke Energy Florida
Calculation of 2015 Estimated/Actual True-up
For the Period of January through December 2015 (Filed August 4, 2015)

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 100,097,800	$ 97,550,693	$ 103,349,547	$ 112,810,811	$ 128,846,041	$ 134,240,962	$ 676,895,854
	2	Fuel Cost of Power Sold	(3,943,219)	(3,521,334)	(2,126,058)	(2,598,023)	(5,784,393)	(5,380,107)	(23,353,134)
	3	Fuel Cost of Purchased Power	7,520,849	7,910,824	10,237,409	14,882,323	12,928,988	24,457,418	77,937,812
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	8,990,368	8,182,122	8,070,423	9,132,303	10,888,108	10,001,969	55,265,293
	4	Energy Cost of Economy Purchases	452,250	582,968	600,426	654,836	460,058	420,572	3,171,110
	5	Adjustments to Fuel Cost	(14,256)	(21,380)	(143,979)	(17,701)	(17,248)	(16,864)	(231,427)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	113,103,792	110,683,892	119,987,768	134,864,550	147,321,554	163,723,951	789,685,508
B	1	Jurisdictional MWH Sales	2,654,267	2,638,626	2,812,088	2,933,622	3,114,914	3,580,025	17,733,542
	2	Non-Jurisdictional MWH Sales	30,765	17,672	21,095	27,293	40,872	40,062	177,760
	3	TOTAL SALES (Lines B1 + B2)	2,685,032	2,656,298	2,833,182	2,960,915	3,155,787	3,620,087	17,911,302
	4	Jurisdictional % of Total Sales (Line B1/B3)	98.85%	99.33%	99.26%	99.08%	98.70%	98.89%	99.01%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	119,677,266	119,280,708	127,253,695	133,158,428	142,927,573	165,551,705	807,849,374
	1a	RRSSA Refund - $40M	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	20,000,000
	1b	RRSSA Fuel Adjustment	(2,654,267)	(2,638,626)	(2,812,088)	(2,933,622)	(3,114,914)	(3,580,025)	(17,733,542)
	1c	RRSSA Refund - $10M	833,333	833,333	833,333	833,333	833,333	833,333	5,000,000
	2	True-Up Provision	(6,139,350)	(6,139,350)	(6,139,350)	(6,139,350)	(6,139,350)	(6,139,350)	(36,836,100)
	2a	Incentive Provision	(185,988)	(185,988)	(185,988)	(185,988)	(185,988)	(185,988)	(1,115,928)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	114,864,327	114,483,410	122,282,936	128,066,135	137,653,987	159,813,009	777,163,803
	4	Fuel & Net Power Transactions (Line A6)	113,103,792	110,683,892	119,987,768	134,864,550	147,321,554	163,723,951	789,685,508
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	111,968,567	110,105,025	119,161,791	133,693,280	145,481,985	161,990,807	782,401,455
	6	Over/(Under) Recovery (Line 3 - Line 5)	2,895,760	4,378,385	3,121,145	(5,627,146)	(7,827,998)	(2,177,798)	(5,237,651)
	7	Interest Provision	(4,604)	(3,822)	(3,031)	(1,981)	(2,352)	(2,598)	(18,388)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	2,891,156	4,374,563	3,118,113	(5,629,126)	(7,830,350)	(2,180,396)	(5,256,039)
	9	Plus: Prior Period Balance	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)
	10	Plus: Cumulative True-Up Provision	6,139,350	12,278,700	18,418,050	24,557,400	30,696,750	36,836,100	36,836,100
	11	Subtotal Prior Period True-up	(55,927,885)	(49,788,535)	(43,649,185)	(37,509,835)	(31,370,485)	(25,231,135)	(25,231,135)
	12	Regulatory Accounting Adjustment	0	0	0	0	0	0	-
	13	TOTAL TRUE-UP BALANCE	($53,036,729)	($42,522,816)	($33,265,353)	($32,755,129)	($34,446,129)	($30,487,176)	($30,487,175)

Duke Energy Florida
Calculation of 2015 Estimated/Actual True-up
For the Period of January through December 2015 (Filed August 4, 2015)

			JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 133,700,347	$ 136,097,823	$ 126,593,806	$ 104,928,147	$ 92,423,994	$ 105,359,517	$ 1,375,999,488
	2	Fuel Cost of Power Sold	(3,094,091)	(3,019,450)	(2,848,461)	(2,645,355)	(2,066,890)	(1,256,433)	(38,283,814)
	3	Fuel Cost of Purchased Power	17,416,030	17,013,076	15,192,693	22,949,573	7,386,550	5,093,508	162,989,242
	3a	Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0
	3b	Energy Payments to Qualified Facilities	10,312,561	10,297,360	9,958,969	8,056,488	11,106,909	11,872,346	116,869,926
	4	Energy Cost of Economy Purchases	671,734	788,613	1,296,819	1,462,896	622,471	270,008	8,283,651
	5	Adjustments to Fuel Cost	(15,475)	(15,475)	(15,475)	(15,475)	(15,475)	(15,475)	(324,278)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	158,991,105	161,161,947	150,178,352	134,736,273	109,457,559	121,323,471	1,625,534,215
B	1	Jurisdictional MWH Sales	3,699,594	3,724,196	3,756,113	3,466,070	2,919,517	2,724,882	38,023,915
	2	Non-Jurisdictional MWH Sales	24,596	28,023	29,483	26,440	20,393	15,140	321,835
	3	TOTAL SALES (Lines B1 + B2)	3,724,190	3,752,219	3,785,596	3,492,510	2,939,910	2,740,022	38,345,749
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.34%	99.25%	99.22%	99.24%	99.31%	99.45%	99.16%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	170,744,713	171,885,672	173,365,900	159,914,463	134,566,793	125,540,147	1,743,867,062
	1a	RRSSA Refund - $40M	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	40,000,000
	1b	RRSSA Fuel Adjustment	(3,699,594)	(3,724,196)	(3,756,113)	(3,466,070)	(2,919,517)	(2,724,882)	(38,023,915)
	1c	RRSSA Refund - $10M	833,333	833,333	833,333	833,333	833,333	833,333	10,000,000
	2	True-Up Provision	(6,139,350)	(6,139,350)	(6,139,350)	(6,139,350)	(6,139,350)	(6,139,353)	(73,672,203)
	2a	Incentive Provision	(185,988)	(185,988)	(185,988)	(185,988)	(185,988)	(185,985)	(2,231,853)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	164,886,447	166,002,805	167,451,116	154,289,722	129,488,604	120,656,594	1,679,939,091
	4	Fuel & Net Power Transactions (Line A6)	158,991,105	161,161,947	150,178,352	134,736,273	109,457,559	121,323,471	1,625,534,215
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	158,023,894	160,036,409	149,084,444	133,781,808	108,758,827	120,718,933	1,612,805,769
	6	Over/(Under) Recovery (Line 3 - Line 5)	6,862,553	5,966,396	18,366,672	20,507,914	20,729,777	(62,339)	67,133,322
	7	Interest Provision	(1,914)	(910)	555	2,600	4,741	6,058	(7,258)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	6,860,639	5,965,486	18,367,226	20,510,514	20,734,518	(56,281)	67,126,063
	9	Plus: Prior Period Balance	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)
	10	Plus: Cumulative True-Up Provision	42,975,450	49,114,800	55,254,150	61,393,500	67,532,850	73,672,203	73,672,203
	11	Subtotal Prior Period True-up	(19,091,785)	(12,952,435)	(6,813,085)	(673,735)	5,465,615	11,604,968	11,604,968
	12	Regulatory Accounting Adjustment	0	0	0	0	0	0	-
	13	TOTAL TRUE-UP BALANCE	($17,487,187)	($5,382,350)	$19,124,226	$45,774,090	$72,647,958	$78,731,030	$78,731,030

Duke Energy Florida
Fuel and Net Power Cost Variance Analysis
January through December 2015

	(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 **	191,452,381	(179,869,137)	4,892,255	16,475,499
3	Coal	(76,314,164)	12,979,100	5,336,304	(57,998,760)
4	Gas	55,482,332	55,373,167	(171,306,346)	(60,450,847)
5	Nuclear	0	0	0	0
6	Other Fuel	0	0	0	0
7	Total Generation	170,620,549	(111,516,870)	(161,077,787)	(101,974,108)
8	Firm Purchases	119,492,398	0	(48,104,684)	71,387,714
9	Economy Purchases	(12,532,924)	0	1,560,064	(10,972,860)
10	Schedule E Purchases	0	0	0	0
11	Qualifying Facilities	(15,893,869)	0	(11,524,996)	(27,418,865)
12	Total Purchases	91,065,605	0	(58,069,616)	32,995,989
13	Economy Sales	0	0	0	0
14	Other Power Sales	(2,711,075)	0	(1,305,043)	(4,016,118)
15	Supplemental Sales	(13,267,453)	0	5,518,147	(7,749,306)
16	Total Sales	(15,978,528)	0	4,213,104	(11,765,424)
17	Nuclear Fuel Disposal Cost	0	0	0	0
18	Nuclear Decom & Decon	0	0	0	0
	Other Jurisdictional Adjustments:				
19a	RRSSA Refunds & Adjustments	0	0	40,190,452	40,190,452
19b	Sch A2 Page 1 of 2 Line 6b, excl RRSSA	0	0	2,015,944	2,015,944
20	Total Fuel and Net Power Cost Variance	245,707,626	(111,516,870)	(172,727,903)	(38,537,147)

** The magnitude of the offsetting MWH and Heat Rate variances is driven by actual oil peaker generation as compared to the projection, which attributed the majority of light oil usage to startup activities. Total 2015 Light Oil expense was $21 million.

160001-EI
Witness: Menendez
Exhibit: CAM-1T (Sheet 7 of 7)

Duke Energy Florida
Summary of Revised and Restated Settlement Agreement (RRSSA) Adjustments
For the Period of January through December 2015

	Retail:	Actual Jan-15	Actual Feb-15	Actual Mar-15	Actual Apr-15	Actual May-15	Actual Jun-15	Actual Jul-15	Actual Aug-15	Actual Sep-15	Actual Oct-15	Actual Nov-15	Actual Dec-15	12 Month Period	Schedule Reference	RRSSA Paragraph
1	RRSSA Refund ($40 million)	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	40,000,000	CAM-1T Sheets 2&3, line C1a	6.b.
2	RRSSA Refund ($10 million)	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	10,000,000	CAM-1T Sheets 2&3, line C1c	6.a.
3	Total RRSSA Refunds (Lines 2 + 3)	4,166,667	4,166,667	4,166,667	4,166,667	4,166,667	4,166,667	4,166,667	4,166,667	4,166,667	4,166,667	4,166,667	4,166,667	50,000,000		
4	Retail mWh Sales	2,654,267	2,638,626	2,812,088	2,933,622	3,114,914	3,580,025	3,728,754	3,837,385	3,761,238	3,282,016	3,354,008	2,856,238	38,553,182	CAM-1T Sheets 2&3, line B1	
5	RRSSA Fuel Adjustment ($/mWh)	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00			7.a. / 7.a(i)
6	Total RRSSA Fuel Adjustment to Revenue (Line 5 * 6)	(2,654,267)	(2,638,626)	(2,812,088)	(2,933,622)	(3,114,914)	(3,580,025)	(3,728,754)	(3,837,385)	(3,761,238)	(3,282,016)	(3,354,008)	(2,856,238)	(38,553,182)	CAM-1T Sheets 2&3, line C1b	

Duke Energy Florida
Capacity Cost Recovery Clause
Summary of Actual True-Up Amount
January through December 2015

Line No.	Description	Actual	Original Estimate	Variance
	Jurisdictional:			
1	Capacity Cost Recovery Revenues Sheet 2 of 3, Line 41	$ 420,726,463	$ 492,144,492	$ (71,418,029)
2	Capacity Cost Recovery Expenses Sheet 2 of 3, Line 37	442,474,325	492,144,492	(49,670,167)
3	Plus/(Minus) Interest Provision Sheet 2 of 3, Line 44	(51,769)	0	(51,769)
4	Sub Total Current Period Over/(Under) Recovery Sheet 2 of 3, Line 45	$ (21,799,631)	$ -	$ (21,799,631)
5	Prior Period True-up - January through December 2015- Over/(Under) Recovery Sheet 2 of 3, Line 46	(30,953,685)	(16,991,246)	(13,962,439)
6	Prior Period True-up - January through December 2015 - (Refunded)/Collected Sheet 2 of 3, Line 47	16,991,246	16,991,246	0
7	Actual True-up ending balance Over/(Under) recovery for the period January through December 2015 Sheet 2 of 3, Line 50	$ (35,762,070)	$ -	$ (35,762,070)
8	Estimated True-up ending balance for the period included in the filing of Levelized Fuel Cost Factors January through December 2015 Docket No. 150001-EI. (Sheet 3 of 3, Line 50)	(38,643,255)		
9	Total Over/(Under) Recovery for the period January through December 2015 (Line 7 - Line 8)	$ 2,881,185		

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 3
PARTY: DUKE ENERGY FLORIDA, LLC – (DIRECT)
DESCRIPTION: Christopher A. Menendez CAM-2T

Duke Energy Florida
Capacity Cost Recovery Clause
Calculation of Actual True-Up
January Through December 2015

		ACTUAL JAN	ACTUAL FEB	ACTUAL MAR	ACTUAL APR	ACTUAL MAY	ACTUAL JUN	ACTUAL JUL	ACTUAL AUG	ACTUAL SEP	ACTUAL OCT	ACTUAL NOV	ACTUAL DEC	YTD
1	**Base Production Level Capacity Charges:**													
2	Orange Cogen (ORANGECO)	3,108,487	3,266,545	3,266,545	3,266,545	3,266,545	3,266,545	3,266,545	3,266,545	3,266,545	3,266,545	3,266,545	3,266,545	39,040,487
3	Orlando Cogen Limited (ORLACOGL)	4,390,316	4,602,317	4,594,986	4,491,065	4,619,448	4,619,448	4,619,448	4,619,448	4,619,448	4,619,448	4,619,448	(4,170,709)	46,244,108
4	Pasco County Resource Recovery (PASCOUNT)	1,483,270	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	18,836,540
5	Pinellas County Resource Recovery (PINCOUNT)	3,530,828	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	44,839,155
6	Polk Power Partners, L.P. (MULBERRY)	5,999,259	6,306,018	6,306,018	6,306,018	6,306,018	6,287,309	6,306,018	6,306,018	6,306,018	6,306,018	6,306,018	6,306,018	75,346,748
7	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	661,873	698,574	715,513	729,448	741,070	754,330	717,450	677,120	665,502	655,232	623,134	622,230	8,261,478
8	Southern - Scherer	1,750,402	1,787,399	1,756,170	1,757,178	1,824,402	3,375,058	1,767,776	1,767,514	1,767,518	1,765,673	1,765,484	1,765,673	22,850,249
9	Calpine Osprey	1,405,950	1,465,539	1,443,650	1,443,650	1,443,650	1,443,650	1,443,650	1,443,650	1,443,650	1,443,650	1,443,650	1,443,650	17,307,989
10	Subtotal - Base Level Capacity Charges	22,330,384	23,459,265	23,415,755	23,326,778	23,534,006	25,079,213	23,453,759	23,413,168	23,401,554	23,389,439	23,357,152	14,566,281	272,726,754
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 Charges	20,741,577	21,790,139	21,749,724	21,667,078	21,859,562	23,294,827	21,785,024	21,747,321	21,736,533	21,725,280	21,695,291	13,529,890	253,322,245
13	**Intermediate Production Level Capacity Charges:**													
14	Southern - Franklin	3,119,543	3,290,615	3,174,459	3,182,635	3,179,430	2,251,554	3,181,573	3,180,294	3,504,765	3,171,307	3,170,383	3,171,307	37,577,865
15	Schedule H Capacity Sales-NSB	(14,792)	(14,792)	(14,792)	(14,792)	(16,080)	(16,080)	0	0	0	0	0	0	(91,328)
16	Subtotal - Intermediate Level Capacity Charges	3,104,751	3,275,823	3,159,667	3,167,843	3,163,350	2,235,474	3,181,573	3,180,294	3,504,765	3,171,307	3,170,383	3,171,307	37,486,537
17	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%	
18	Intermediate Level Jurisdict. Capacity Charges	2,257,247	2,381,621	2,297,173	2,303,117	2,299,850	1,625,256	2,313,099	2,312,169	2,548,069	2,305,636	2,304,964	2,305,636	27,253,837
19	**Peaking Production Level Capacity Charges:**													
20	Chattahoochee Capacity Purchase	0	0	0	0	0	0	0	0	0	0	0	0	-
21	Vandolah Capacity - Northern Star	2,932,374	2,895,800	1,886,774	1,947,064	2,800,877	5,785,668	5,780,497	5,715,411	2,715,406	1,919,503	2,016,937	2,947,051	39,343,362
22	Shady Hills Power Company LLC	1,410,076	1,646,992	1,406,900	1,440,840	1,912,680	3,888,000	3,888,000	3,886,445	1,814,400	1,366,200	1,366,200	1,941,646	25,968,379
23	Subtotal -Peaking Level Capacity Charges	4,342,450	4,542,793	3,293,674	3,387,903	4,713,557	9,673,668.05	9,668,497	9,601,856	4,529,806	3,285,703	3,383,137	4,888,697	65,311,741
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 Charges	4,165,452	4,357,629	3,159,424	3,249,812	4,521,433	9,279,369	9,274,409	9,210,484	4,345,171	3,151,777	3,245,241	4,689,434	62,649,635
26	**Other Capacity Charges:**													
27	Retail Wheeling	(44,982)	(109,006)	(31,099)	(4,143)	(42,143)	(19,211)	(10,188)	(49,327)	(24,634)	(9,153)	(30,188)	(20,424)	(394,498)
28	Total Other Capacity Charges	(44,982)	(109,006)	(31,099)	(4,143)	(42,143)	(19,211)	(10,188)	(49,327)	(24,634)	(9,153)	(30,188)	(20,424)	(394,498)
29														
30	**Subtotal Jurisdictional Capacity Charges (lines 12+18+25+28)**	27,119,295	28,420,383	27,175,221	27,215,864	28,638,702	34,180,241	33,362,345	33,220,647	28,605,140	27,173,540	27,215,307	20,504,536	342,831,219
31														
32	**Nuclear Cost Recovery Clause Charges:**													
33	Levy Costs ①	9,215,650	9,145,040	9,074,430	9,003,820	0	0	0	0	0	0	0	0	36,438,940
34	CR-3 Uprate Costs	5,442,716	5,412,634	5,382,366	5,352,099	5,321,833	5,291,141	5,260,871	5,208,780	5,178,331	5,148,065	5,117,797	5,087,530	63,204,163
35	**Total NCRC Costs - Order No. PSC-14-0701-FOF-EI**	14,658,366	14,557,674	14,456,796	14,355,919	5,321,833	5,291,141	5,260,871	5,208,780	5,178,331	5,148,065	5,117,797	5,087,530	99,643,103
36														
37	**Total Jurisdictional Capacity Charges (Lines 30 + 35)**	41,777,661	42,978,058	41,632,018	41,571,783	33,960,536	39,471,382	38,623,216	38,429,428	33,783,470	32,321,604	32,333,104	25,592,065	442,474,325
38	**Capacity Revenues:**													
39	Capacity Cost Recovery Revenues (net of tax)	35,474,797	35,917,927	38,743,786	38,282,459	33,024,082	37,697,540	39,725,599	39,816,063	39,512,524	34,329,371	35,253,377	29,940,179	437,717,704
40	Prior Period True-Up Provision	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(16,991,241)
41	Current Period CCR Revenues (net of tax)	34,058,861	34,501,991	37,327,849	36,866,522	31,608,145	36,281,603	38,309,663	38,400,126	38,096,587	32,913,434	33,837,441	28,524,243	420,726,463
42	**True-Up Provision - Current Year (Acct 1823203/2543203)**													
43	True-Up Provision - Over/(Under) Recov (line 41-line 37)	(7,718,800)	(8,476,067)	(4,304,169)	(4,705,261)	(2,352,390)	(3,189,779)	(313,553)	(29,302)	4,313,117	591,830	1,504,337	2,932,177	(21,747,862)
44	Interest Provision for the Month	(2,831)	(3,263)	(3,661)	(2,932)	(3,568)	(4,187)	(4,214)	(4,629)	(4,788)	(4,402)	(4,571)	(8,723)	(51,769)
45	Total current month over/(under) recovery (Acct 4560097,5572001)	(7,721,631)	(16,200,961)	(20,508,791)	(25,216,984)	(27,572,942)	(30,766,908)	(31,084,675)	(31,118,606)	(26,810,277)	(26,222,848)	(24,723,083)	(21,799,629)	(21,799,631)
46	Prior Year True-Up & Interest Prov. (Begin Bal)-Over/(Under)	(30,953,685)	(29,537,749)	(28,121,812)	(26,705,875)	(25,289,939)	(23,874,002)	(22,458,065)	(21,042,129)	(19,626,192)	(18,210,255)	(16,794,319)	(15,378,382)	(30,953,685)
47	Prior YearTrue-Up Collected/(Refunded)	1,415,937	1,415,937	1,415,937	1,415,937	1,415,937	1,415,937	1,415,937	1,415,937	1,415,937	1,415,937	1,415,937	1,415,937	16,991,246
48	Prior Year True-Up & Interest Provision End Bal - (DR)/CR	(29,537,749)	(28,121,812)	(26,705,875)	(25,289,939)	(23,874,002)	(22,458,065)	(21,042,129)	(19,626,192)	(18,210,255)	(16,794,319)	(15,378,382)	(13,962,445)	(13,962,439)
49														
50	**Net Capacity True-up Over/(Under) (lines 45+48)**	($37,259,380)	($44,322,773)	($47,214,667)	($50,506,923)	($51,446,944)	($53,224,973)	($52,126,803)	($50,744,798)	($45,020,532)	($43,017,167)	($40,101,465)	($35,762,074)	($35,762,070)

① Per Order No. PSC-15-0176-TRF-EI, DEF terminated the Levy Fixed Charge beginning May 2015.

Duke Energy Florida
Capacity Cost Recovery Clause
Calculation of Estimated/Actual True-Up
January- December 2015 (Filed 08/04/2015)

		ACT Jan-15	ACT Feb-15	ACT Mar-15	ACT Apr-15	ACT May-15	ACT Jun-15	EST Jul-15	EST Aug-15	EST Sep-15	EST Oct-15	EST Nov-15	EST Dec-15	TOTAL
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	3,108,487	3,266,545	3,266,545	3,266,545	3,266,545	3,266,545	3,073,960	3,073,960	3,073,960	3,073,960	3,073,960	3,073,960	37,884,974
3	Orlando Cogen Limited (ORLACOGL)	4,390,316	4,602,317	4,594,986	4,491,065	4,619,448	4,619,448	4,143,450	4,143,450	4,143,450	4,143,450	4,143,450	4,143,450	52,178,278
4	Pasco County Resource Recovery (PASCOUNT)	1,483,270	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	18,836,540
5	Pinellas County Resource Recovery (PINCOUNT)	3,530,828	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	44,839,155
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	5,999,259	6,306,018	6,306,018	6,306,018	6,306,018	6,287,309	5,815,550	5,815,550	5,815,550	5,815,550	5,815,550	5,815,550	72,403,940
7	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	661,873	698,574	715,513	729,448	741,070	754,330	782,100	782,100	782,100	782,100	782,100	782,100	8,993,409
8	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Southern - Scherer	1,750,402	1,787,399	1,756,170	1,757,178	1,824,402	3,375,058	1,744,736	1,744,736	1,744,736	1,744,736	1,744,736	1,744,736	22,719,024
10	Calpine Osprey	1,405,950	1,465,539	1,443,650	1,443,650	1,443,650	1,443,650	1,405,950	1,405,950	1,405,950	1,405,950	1,405,950	1,405,950	17,081,789
11	Subtotal - Base Level Capacity Costs	22,330,384	23,459,265	23,415,755	23,326,778	23,534,006	25,079,213	22,298,618	22,298,618	22,298,618	22,298,618	22,298,618	22,298,618	274,937,109
12	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%	
13	Base Level Jurisdictional Capacity Costs	20,741,577	21,790,139	21,749,724	21,667,078	21,859,562	23,294,827	20,712,071	20,712,071	20,712,071	20,712,071	20,712,071	20,712,071	255,375,334
14	**Intermediate Production Level Capacity Costs**													
15	Southern - Franklin	3,119,543	3,290,615	3,174,459	3,182,635	3,179,430	2,251,554	3,185,168	3,185,168	3,185,168	3,185,168	3,185,168	3,185,168	37,309,244
16	Schedule H Capacity Sales - NSB	(14,792)	(14,792)	(14,792)	(14,792)	(16,080)	(16,080)	(16,080)	(16,080)	(16,080)	(16,080)	(16,080)	(16,080)	(187,808)
17	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Subtotal - Intermediate Level Capacity Costs	3,104,751	3,275,823	3,159,667	3,167,843	3,163,350	2,235,474	3,169,088	3,169,088	3,169,088	3,169,088	3,169,088	3,169,088	37,121,436
19	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%	
20	Intermediate Level Jurisdictional Capacity Costs	2,257,247	2,381,621	2,297,173	2,303,117	2,299,850	1,625,256	2,304,022	2,304,022	2,304,022	2,304,022	2,304,022	2,304,022	26,988,397
21	**Peaking Production Level Capacity Costs**													
22	Chattahoochee	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Vandolah (RRI)	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Shady Hills Power Company LLC	1,410,076	1,646,992	1,406,900	1,440,840	1,912,680	3,888,000	3,887,109	3,887,109	1,813,984	1,365,741	1,365,741	1,970,869	25,996,042
25	Vandolah (NSG)	2,932,374	2,895,800	1,886,774	1,947,064	2,800,877	5,785,668	5,554,010	5,509,420	2,636,711	1,942,223	1,986,813	2,795,377	38,673,111
26	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Subtotal - Peaking Level Capacity Costs	4,342,450	4,542,793	3,293,674	3,387,903	4,713,557	9,673,668	9,441,119	9,396,529	4,450,696	3,307,964	3,352,554	4,766,247	64,669,152
28	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%	
29	Peaking Level Jurisdictional Capacity Costs	4,165,452	4,357,629	3,159,424	3,249,812	4,521,433	9,279,369	9,056,299	9,013,526	4,269,285	3,173,131	3,215,904	4,571,974	62,033,238
30	**Other Capacity Costs**													
31	Retail Wheeling	(44,982)	(109,006)	(31,099)	(4,143)	(42,143)	(19,211)	(43,542)	(16,088)	(999)	(8,514)	(13,490)	(3,004)	(336,221)
32	Other Jurisdictional Capacity Costs	(44,982)	(109,006)	(31,099)	(4,143)	(42,143)	(19,211)	(43,542)	(16,088)	(999)	(8,514)	(13,490)	(3,004)	(336,221)
33	**Subtotal Jurisd Capacity Costs (Line 13+20+29+32)**	27,119,295	28,420,383	27,175,221	27,215,864	28,638,702	34,180,241	32,028,850	32,013,531	27,284,380	26,180,711	26,218,507	27,585,063	344,060,748
34	**Nuclear Cost Recovery Clause Costs (net of tax)**													
35	Levy Costs ①	9,215,650	9,145,040	9,074,430	9,003,820	-	-	-	-	-	-	-	-	36,438,940
36	CR3 Uprate Costs	5,442,716	5,412,634	5,382,366	5,352,099	5,321,833	5,291,141	5,260,871	5,208,780	5,178,331	5,148,065	5,117,797	5,087,530	63,204,163
37	**Total NCRC Costs - Order No. PSC-14-0701-FOF-EI**	14,658,366	14,557,674	14,456,796	14,355,919	5,321,833	5,291,141	5,260,871	5,208,780	5,178,331	5,148,065	5,117,797	5,087,530	99,643,103
38	**Total Jurisdictional Capacity Costs (Line 33+37)**	41,777,661	42,978,057	41,632,018	41,571,783	33,960,535	39,471,382	37,289,721	37,222,312	32,462,711	31,328,775	31,336,304	32,672,593	443,703,851
39	**Capacity Revenues**													
40	Capacity Cost Recovery Revenues (net of tax) ①	35,474,797	35,917,927	38,743,786	38,282,459	33,024,082	37,697,540	39,548,662	39,811,654	40,152,847	37,052,286	31,209,639	29,128,994	436,044,671
41	Prior Period True-Up Provision Over/(Under) Recovery	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(16,991,240)
42	**Current Period Revenues (net of tax)**	34,058,861	34,501,991	37,327,849	36,866,522	31,608,145	36,281,603	38,132,725	38,395,717	38,736,910	35,636,349	29,793,702	27,713,057	419,053,431
43	**True-Up Provision**													
44	True-Up Provision - Over/(Under) Recov (Line 42-38)	(7,718,800)	(8,476,066)	(4,304,169)	(4,705,261)	(2,352,389)	(3,189,779)	843,004	1,173,405	6,274,199	4,307,574	(1,542,602)	(4,959,535)	(24,650,419)
45	Interest Provision for the Month	(2,831)	(3,263)	(3,661)	(2,932)	(3,568)	(4,187)	(2,039)	(1,935)	(1,628)	(1,399)	(1,404)	(1,545)	(30,390)
46	Current Cycle Balance - Over/(Under)	(7,721,631)	(16,200,960)	(20,508,790)	(25,216,983)	(27,572,940)	(30,766,906)	(29,925,940)	(28,754,471)	(22,481,899)	(18,175,724)	(19,719,730)	(24,680,809)	(24,680,809)
47	Prior Period Balance - Over/(Under) Recovered	(30,953,685)	(30,953,685)	(30,953,685)	(30,953,685)	(30,953,685)	(30,953,685)	(30,953,685)	(30,953,685)	(30,953,685)	(30,953,685)	(30,953,685)	(30,953,685)	(30,953,685)
48	Prior Period Cumulative True-Up Collected/(Refunded)	1,415,937	2,831,873	4,247,810	5,663,747	7,079,683	8,495,620	9,911,557	11,327,493	12,743,430	14,159,367	15,575,303	16,991,240	16,991,240
49	Prior Period True-up Balance - Over/(Under)	(29,537,749)	(28,121,812)	(26,705,875)	(25,289,939)	(23,874,002)	(22,458,065)	(21,042,129)	(19,626,192)	(18,210,255)	(16,794,319)	(15,378,382)	(13,962,445)	(13,962,445)
50	**Net Capacity True-up Over/(Under) (Line 46+49)**	($37,259,380)	($44,322,772)	($47,214,666)	($50,506,922)	($51,446,942)	($53,224,971)	($50,968,069)	($48,380,663)	($40,692,155)	($34,970,043)	($35,098,112)	($38,643,255)	($38,643,255)

DUKE ENERGY FLORIDA
FUEL AND PURCHASED POWER

DECEMBER 2015

		$				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	FUEL COST OF SYSTEM NET GENERATION (SCH A3)	87,562,430	108,082,070	(20,519,640)	(19.0)	2,609,742	2,732,958	(123,216)	(4.5)	3.3552	3.9548	(0.5996)	(15.2)
2	SPENT NUCLEAR FUEL DISPOSAL COST	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3	COAL CAR INVESTMENT	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3a	NUCLEAR DECOMMISSIONING AND DECONTAMINATION	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4	ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	(18,543)	(3,360,069)	3,341,526	(99.5)	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4a	ADJUSTMENTS TO FUEL COST - DISPOSAL COST REFUND	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
5	TOTAL COST OF GENERATED POWER	87,543,887	104,722,001	(17,178,114)	(16.4)	2,609,742	2,732,958	(123,216)	(4.5)	3.3545	3.8318	(0.4773)	(12.5)
6	ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	7,720,621	3,736,315	3,984,306	106.6	260,791	77,721	183,070	235.6	2.9605	4.8073	(1.8468)	(38.4)
7	ENERGY COST OF SCH C,X ECONOMY PURCH - BROKER (SCH A9)	5,423	0	5,423	0.0	317	0	317	0.0	1.7108	0.0000	1.7108	0.0
8	ENERGY COST OF ECONOMY PURCH - NON-BROKER (SCH A9)	96,354	644,380	(548,026)	(85.1)	3,255	14,739	(11,484)	(77.9)	2.9602	4.3719	(1.4117)	(32.3)
9	ENERGY COST OF SCH E PURCHASES (SCH A9)	-	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
10	CAPACITY COST OF ECONOMY PURCHASES (SCH A9)	-	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
11	PAYMENTS TO QUALIFYING FACILITIES (SCH A8)	10,642,495	12,643,543	(2,001,048)	(15.8)	259,740	276,983	(17,243)	(6.2)	4.0974	4.5647	(0.4673)	(10.2)
12	TOTAL COST OF PURCHASED POWER	18,464,893	17,024,238	1,440,655	8.5	524,103	369,443	154,660	41.9	3.5231	4.6081	(1.0850)	(23.6)
13	TOTAL AVAILABLE MWH					3,133,845	3,102,401	31,444	1.0				
14	FUEL COST OF ECONOMY SALES (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
14a	GAIN ON ECONOMY SALES - 100% (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
15	FUEL COST OF OTHER POWER SALES (SCH A6)	(90,419)	(136,796)	46,377	(33.9)	(4,502)	(4,380)	(122)	2.8	2.0084	3.1232	(1.1148)	(35.7)
15a	GAIN ON OTHER POWER SALES - 100% (SCH A6)	(21,160)	(30,095)	8,935	(29.7)	(4,502)	(4,380)	(122)	2.8	0.4700	0.6871	(0.2171)	(31.6)
15b	GAIN ON TOTAL POWER SALES - 20% (SCH A6)	4,232	0	4,232	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
16	FUEL COST OF SEMINOLE BACK-UP SALES (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
17	FUEL COST OF STRATIFIED SALES	(413,873)	(1,089,118)	675,245	(62.0)	(25,621)	(28,207)	2,586	(9.2)	1.6154	3.8612	(2.2458)	(58.2)
18	TOTAL FUEL COST AND GAINS ON POWER SALES	(521,220)	(1,256,009)	734,789	(58.5)	(30,123)	(32,587)	2,464	(7.6)	1.7303	3.8543	(2.1240)	(55.1)
19	NET INADVERTENT AND WHEELED INTERCHANGE					10,908	0	10,908					
20	TOTAL FUEL AND NET POWER TRANSACTIONS	105,487,560	120,490,230	(15,002,670)	(12.5)	3,114,630	3,069,814	44,816	1.5	3.3868	3.9250	(0.5382)	(13.7)
21	NET UNBILLED	3,548,054	4,110,607	(562,553)	(13.7)	(104,760)	(104,729)	(31)	0.0	0.1234	0.1477	(0.0243)	(16.5)
22	COMPANY USE	577,350	471,000	106,350	22.6	(17,047)	(12,000)	(5,047)	42.1	0.0201	0.0169	0.0032	18.9
23	T & D LOSSES	3,997,488	6,660,933	(2,663,445)	(40.0)	(118,030)	(169,705)	51,675	(30.5)	0.1391	0.2393	(0.1002)	(41.9)
24	ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 2)	105,487,560	120,490,230	(15,002,670)	(12.5)	2,874,793	2,783,380	91,413	3.3	3.6694	4.3289	(0.6595)	(15.2)
25	WHOLESALE KWH SALES (EXCLUDING STRATIFIED SALES)	(685,669)	(650,647)	(35,022)	5.4	(18,555)	(15,140)	(3,415)	22.6	3.6952	4.2975	(0.6023)	(14.0)
26	JURISDICTIONAL KWH SALES	104,801,891	119,839,583	(15,037,692)	(12.6)	2,856,238	2,768,240	87,998	3.2	3.6692	4.3291	(0.6599)	(15.2)
27	JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.00052	104,856,388	120,016,945	(15,160,557)	(12.6)	2,856,238	2,768,240	87,998	3.2	3.6711	4.3355	(0.6644)	(15.3)
28	PRIOR PERIOD TRUE-UP	6,139,350	6,139,353	(3)	0.0	2,856,238	2,768,240	87,998	3.2	0.2149	0.2218	(0.0069)	(3.1)
28a	MARKET PRICE TRUE-UP	0	0	0	0.0	2,856,238	2,768,240	87,998	3.2	0.0000	0.0000	0.0000	0.0
28b	RECOVERY OF PRIOR PERIOD NUCLEAR REPLACEMENT COST	0	0	0	0.0	2,856,238	2,768,240	87,998	3.2	0.0000	0.0000	0.0000	0.0
29	TOTAL JURISDICTIONAL FUEL COST	110,995,738	126,156,298	(15,160,560)	(12.0)	2,856,238	2,768,240	87,998	3.2	3.8860	4.5573	(0.6713)	(14.7)
30	REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0.0
31	FUEL COST ADJUSTED FOR TAXES									3.8888	4.5606	(0.6718)	(14.7)
32	GPIF	185,988	185,985			2,856,238	2,768,240			0.0065	0.0067	(0.0002)	(3.0)
33	TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									3.895	4.567	(0.672)	(14.7)

*Line 15a. MWH Data for Infomational Purposes Only

DUKE ENERGY FLORIDA
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
YEAR TO DATE - DECEMBER 2015

		$				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	FUEL COST OF SYSTEM NET GENERATION (SCH A3)	1,348,576,285	1,450,550,393	(101,974,108)	(7.0)	35,018,627	35,719,602	(700,975)	(2.0)	3.8510	4.0609	(0.2099)	(5.2)
2	SPENT NUCLEAR FUEL DISPOSAL COST	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3	COAL CAR INVESTMENT	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3a	NUCLEAR DECOMMISSIONING AND DECONTAMINATION	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4	ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	1,852,721	(40,353,675)	42,206,396	(104.6)	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4a	ADJUSTMENTS TO FUEL COST - DISPOSAL COST REFUND	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
5	TOTAL COST OF GENERATED POWER	1,350,429,005	1,410,196,718	(59,767,713)	(4.2)	35,018,627	35,719,602	(700,975)	(2.0)	3.8563	3.9480	(0.0917)	(2.3)
6	ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	173,229,452	101,841,738	71,387,714	70.1	4,384,597	2,017,470	2,367,127	117.3	3.9509	5.0480	(1.0971)	(21.7)
7	ENERGY COST OF SCH C,X ECONOMY PURCH - BROKER (SCH A9)	20,278	0	20,278	0.0	838	0	838	0.0	2.4198	0.0000	2.4198	0.0
8	ENERGY COST OF ECONOMY PURCH - NON-BROKER (SCH A9)	5,358,735	16,351,874	(10,993,139)	(67.2)	82,422	356,500	(274,078)	(76.9)	6.5016	4.5868	1.9148	41.8
9	ENERGY COST OF SCH E PURCHASES (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
10	CAPACITY COST OF ECONOMY PURCHASES (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
11	PAYMENTS TO QUALIFYING FACILITIES (SCH A8)	117,723,823	145,142,688	(27,418,865)	(18.9)	2,749,552	3,087,667	(338,115)	(11.0)	4.2816	4.7007	(0.4191)	(8.9)
12	TOTAL COST OF PURCHASED POWER	296,332,288	263,336,300	32,995,988	12.5	7,217,409	5,461,637	1,755,772	32.2	4.1058	4.8216	(0.7158)	(14.9)
13	TOTAL AVAILABLE MWH					42,236,036	41,181,239	1,054,797	2.6				
14	FUEL COST OF ECONOMY SALES (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
14a	GAIN ON ECONOMY SALES - 100% (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
15	FUEL COST OF OTHER POWER SALES (SCH A6)	(5,814,591)	(4,199,152)	(1,615,439)	38.5	(193,138)	(126,300)	(66,838)	52.9	3.0106	3.3247	(0.3141)	(9.5)
15a	GAIN ON OTHER POWER SALES - 100% (SCH A6)	(3,720,655)	(923,813)	(2,796,842)	302.8	(193,138)	(126,300)	(66,838)	52.9	1.9264	0.7314	1.1950	163.4
15b	GAIN ON TOTAL POWER SALES - 20% (SCH A6)	396,162	0	396,162	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
16	FUEL COST OF SEMINOLE BACK-UP SALES (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
17	FUEL COST OF STRATIFIED SALES	(29,549,697)	(21,800,391)	(7,749,306)	35.6	(885,489)	(550,476)	(335,013)	60.9	3.3371	3.9603	(0.6232)	(15.7)
18	TOTAL FUEL COST AND GAINS ON POWER SALES	(38,688,780)	(26,923,356)	(11,765,424)	43.7	(1,078,627)	(676,776)	(401,851)	59.4	3.5869	3.9782	(0.3913)	(9.8)
19	NET INADVERTENT AND WHEELED INTERCHANGE					236,840	0	236,840					
20	TOTAL FUEL AND NET POWER TRANSACTIONS	1,608,072,513	1,646,609,662	(38,537,149)	(2.3)	41,394,248	40,504,463	889,785	2.2	3.8848	4.0653	(0.1805)	(4.4)
21	NET UNBILLED	2,489,751	4,642,743	(2,152,992)	(46.4)	(64,090)	(93,029)	28,939	(31.1)	0.0064	0.0122	(0.0058)	(47.5)
22	COMPANY USE	6,803,244	5,850,324	952,920	16.3	(175,126)	(144,000)	(31,126)	21.6	0.0175	0.0154	0.0021	13.6
23	T & D LOSSES	87,163,542	91,158,972	(3,995,430)	(4.4)	(2,243,723)	(2,242,422)	(1,301)	0.1	0.2240	0.2397	(0.0157)	(6.6)
24	ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 2)	1,608,072,513	1,646,609,662	(38,537,149)	(2.3)	38,911,309	38,025,012	886,297	2.3	4.1327	4.3303	(0.1976)	(4.6)
25	WHOLESALE KWH SALES (EXCLUDING STRATIFIED SALES)	(15,005,212)	(10,295,986)	(4,709,227)	45.7	(358,128)	(239,422)	(118,706)	49.6	4.1899	4.3004	(0.1105)	(2.6)
26	JURISDICTIONAL KWH SALES	1,593,067,301	1,636,313,677	(43,246,376)	(2.6)	38,553,182	37,785,590	767,591	2.0	4.1321	4.3305	(0.1984)	(4.6)
27	JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.00052	1,594,108,572	1,638,735,421	(44,626,849)	(2.7)	38,553,182	37,785,590	767,591	2.0	4.1348	4.3369	(0.2021)	(4.7)
28	PRIOR PERIOD TRUE-UP	73,672,203	73,672,203	0	0.0	38,553,182	37,785,590	767,591	2.0	0.1911	0.1950	(0.0039)	(2.0)
28a	MARKET PRICE TRUE-UP	0	0	0	0.0	38,553,182	37,785,590	767,591	2.0	0.0000	0.0000	0.0000	0.0
28b	RECOVERY OF PRIOR PERIOD NUCLEAR REPLACEMENT COST	0	0	0	0.0	38,553,182	37,785,590	767,591	2.0	0.0000	0.0000	0.0000	0.0
29	TOTAL JURISDICTIONAL FUEL COST	1,667,780,775	1,712,407,624	(44,626,849)	(2.6)	38,553,182	37,785,590	767,591	2.0	4.3259	4.5319	(0.2060)	(4.6)
30	REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0.0
31	FUEL COST ADJUSTED FOR TAXES									4.3290	4.5352	(0.2061)	(4.6)
32	GPIF	2,231,853	2,231,853			38,553,182	37,785,590			0.0058	0.0059	(0.0001)	101.7
33	TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									4.335	4.541	(0.206)	(4.5)

*Line 15a. MWH Data for Infomational Purposes Only

DUKE ENERGY FLORIDA
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2015

		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	$87,562,430	108,082,070	($20,519,640)	(19.0)	$1,348,576,285	$1,450,550,393	($101,974,108)	(7.0)
1a.	NUCLEAR FUEL DISPOSAL COST	-	0	0	0.0	0	0	0	0.0
1b.	NUCLEAR DECOMMISSIONING AND DECONTAMINATION	-	0	0	0.0	0	0	0	0.0
1c.	COAL CAR INVESTMENT	-	0	0	0.0	0	0	0	0.0
2 .	FUEL COST OF POWER SOLD	(90,419)	(136,796)	46,377	(33.9)	(5,814,591)	(4,199,152)	(1,615,439)	38.5
2a.	GAIN ON POWER SALES	(16,928)	(30,095)	13,167	(43.8)	(3,324,492)	(923,813)	(2,400,679)	259.9
3 .	FUEL COST OF PURCHASED POWER	7,720,621	3,736,315	3,984,306	106.6	173,229,452	101,841,738	71,387,714	70.1
3a.	ENERGY PAYMENTS TO QUALIFYING FACILITIES	10,642,495	12,643,543	(2,001,048)	(15.8)	117,723,823	145,142,688	(27,418,865)	(18.9)
3b.	DEMAND & NON FUEL COST OF PURCH POWER	0	0	0	0.0	0	0	0	0.0
4 .	ENERGY COST OF ECONOMY PURCHASES	101,778	644,380	(542,602)	(84.2)	5,379,013	16,351,874	(10,972,861)	(67.1)
5 .	TOTAL FUEL & NET POWER TRANSACTIONS	105,919,976	124,939,417	(19,019,441)	(15.2)	1,635,769,489	1,708,763,728	(72,994,239)	(4.3)
6 .	ADJUSTMENTS TO FUEL COST:								
6a.	FUEL COST OF STRATIFIED SALES	(413,873)	(1,089,118)	675,245	(62.0)	(29,549,697)	(21,800,391)	(7,749,306)	35.6
6b.	OTHER- JURISDICTIONAL ADJUSTMENTS (see detail below)	(18,543)	(3,360,069)	3,341,526	(99.5)	1,852,721	(40,353,675)	42,206,396	(104.6)
6c.	OTHER - PRIOR PERIOD ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
7 .	ADJUSTED TOTAL FUEL & NET PWR TRNS	$105,487,560	$120,490,230	($15,002,670)	(12.5)	$1,608,072,513	$1,646,609,662	($38,537,149)	(2.3)

FOOTNOTE: DETAIL OF LINE 6b ABOVE

INSPECTION & FUEL ANALYSIS REPORTS {Wholesale Portion}	$0	$0	$0	$0	$0	$0
N/A - Not used	0	0	0	0	0	0
UNIVERSITY OF FLORIDA STEAM REVENUE ALLOCATION {Wholesale Portion}	650	0	650	10,980	0	10,980
N/A - Not used	0	0	0	0	0	0
TANK BOTTOM ADJUSTMENT	0	0	0	6,981	0	6,981
AERIAL SURVEY ADJUSTMENT (Coal Pile)	0	0	0	2,182,992	0	2,182,992
RRSSA Refund	0	(3,346,478)	3,346,478	0	(40,190,452)	40,190,452
Interest Amortized for Fuel Refund	(15,576)	(13,591)	(1,986)	(187,418)	(163,223)	(24,195)
Gain/Loss on Disposition of Oil	0	0	0	(125,114)	0	(125,114)
N/A - Not used	0	0	0	0	0	0
NET METER SETTLEMENT	0	0	0	0	0	0
Bartow Outage Replacement Power	0	0	0	0	0	0
Derivative Collateral Interest	(3,616)	0	(3,616)	(35,701)	0	(35,701)
N/A - Not used	0	0	0	0	0	0
SUBTOTAL LINE 6b SHOWN ABOVE	($18,543)	($3,360,069)	$3,341,526	$1,852,721	($40,353,675)	$42,206,396

B.	KWH SALES							
1 .	JURISDICTIONAL SALES	2,856,240,057	2,768,239,922	88,000,135	3.2	38,553,183,288	37,785,590,394	767,592,894	2.0
2 .	NON JURISDICTIONAL (WHOLESALE) SALES	18,555,478	15,140,000	3,415,478	22.6	358,127,542	239,422,000	118,705,542	49.6
3 .	TOTAL SALES	2,874,795,535	2,783,379,922	91,415,613	3.3	38,911,310,830	38,025,012,394	886,298,436	2.3
4 .	JURISDICTIONAL SALES % OF TOTAL SALES	99.35	99.46	(0.11)	(0.1)	99.08	99.37	(0.29)	(0.3)

DUKE ENERGY FLORIDA
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2015

		CURRENT MONTH				YEAR TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
C.	TRUE UP CALCULATION								
1 .	JURISDICTIONAL FUEL REVENUE	$125,316,286	$125,617,437	($301,151)	(0.2)	$1,763,506,241	$1,714,637,871	$48,868,370	2.9
2 .	ADJUSTMENTS:	3,333,333	0	3,333,333	0.0	40,000,000	0	40,000,000	0.0
2a.	REFUND OF $30 MILLION PER RRSSA	833,333	0	833,333	0.0	10,000,000	0	10,000,000	0.0
2b.	INCREASE IN RETAIL FUEL RATE PER RRSSA	(2,856,240)	0	(2,856,240)	0.0	(38,553,183)	0	(38,553,183)	0.0
2c.	TRUE UP PROVISION	(6,139,350)	(6,139,353)	3	0.0	(73,672,203)	(73,672,203)	0	0.0
2d.	INCENTIVE PROVISION	(185,988)	(185,985)	(3)	0.0	(2,231,853)	(2,231,853)	0	0.0
2e.	OTHER: MARKET PRICE TRUE UP	0	0	0	0.0	0	0	0	0.0
3 .	TOTAL JURISDICTIONAL FUEL REVENUE	120,301,374.50	119,292,098.60	1,009,275.90	0.9	1,699,049,002	1,638,733,815	60,315,187	3.7
4 .	ADJ TOTAL FUEL & NET PWR TRNS (LINE A7)	105,487,560	120,490,230	(15,002,670)	-12.45	1,608,072,513	1,646,609,662	(38,537,149)	-2.34
5 .	JURISDICTIONAL SALES % OF TOT SALES (LINE B4)	99	99	(0)	(0.1)	99	99	(0)	(0.3)
6 .	JURISDICTIONAL FUEL & NET POWER TRANSACTIONS (LINE C4 * LINE C5 * 1.00052 LOSS MULTIPLIER)	104,856,388	120,016,945	(15,160,557)	(12.6)	1,594,108,572	1,638,735,421	(44,626,849)	(2.7)
7 .	TRUE UP PROVISION FOR THE MONTH OVER/(UNDER) COLLECTION (LINE C3 - C6)	15,444,986	(724,847)	16,169,833	(2,230.8)	104,940,430	(1,606)	104,942,036	(6,535,277)
8 .	INTEREST PROVISION FOR THE MONTH (LINE D10)	24,322	(135)	24,456	(18,155.7)	17,682	(30,576)	48,258	(158)
9 .	TRUE UP & INTEREST PROVISION BEG OF MONTH/PERIOD	94,954,422	(5,446,554)	100,400,975	(1,843.4)	(62,067,235)	(73,672,203)	11,604,968	(16)
10.	TRUE UP COLLECTED (REFUNDED)	6,139,350	6139353	(3)	0	73,672,203	73,672,203	-	-
11.	END OF PERIOD TOTAL NET TRUE UP (LINES C7 + C8 + C9 + C10)	$116,563,080	-32182.08446	116,595,262	-362298.66	116,563,080	(32,182)	116,595,262	(362,299)
12.	OTHER:	$0				-		-	
13.	END OF PERIOD TOTAL NET TRUE UP (LINES C11 + C12)	116,563,080	(32,182)	116,595,262.15	-362298.66	116,563,080	(32,182)	116,595,262	(362,299)

D.	INTEREST PROVISION					
1 .	BEGINNING TRUE UP (LINE C9)	94,954,422	N/A	--	--	
2 .	ENDING TRUE UP (LINES C7 + C9 + C10 + C12)	116,538,758	N/A	--	--	
3 .	TOTAL OF BEGINNING & ENDING TRUE UP	211,493,180	N/A	--	--	N O T
4 .	AVERAGE TRUE UP (50% OF LINE D3)	105,746,590	N/A	--	--	
5 .	INTEREST RATE - FIRST DAY OF REPORTING MONTH	0.150	N/A	--	--	
6 .	INTEREST RATE - FIRST DAY OF SUBSEQUENT MONTH	0.400	N/A	--	--	
7 .	TOTAL (LINE D5 + LINE D6)	0.550	N/A			
8 .	AVERAGE INTEREST RATE (50% OF LINE D7)	$0	N/A	--	--	

A-3 Generating System Comparative Data Report

Duke Energy Florida

Docket No. 160001-EI
Witness: Menendez
Exhibit No. (CAM-3T)
Schedule: A3-1
Sheet 5 of 9

FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
NET GENERATION ($)				
1 - HEAVY OIL	0	0	0	0.0%
2 - LIGHT OIL	21,114,159	4,211,953	16,475,499	391.2%
3 - COAL	479,549,089	437,953,621	(57,998,760)	(13.2%)
4 - GAS	1,053,354,312	1,008,384,819	(60,450,847)	(6.0%)
5 - NUCLEAR	0	0	0	0.0%
6	0	0	0	0.0%
7	0	0	0	0.0%
8 - TOTAL ($)	1,348,576,284	1,450,550,393	(101,974,109)	(7.0%)
SYSTEM NET GENERATION (MWH)				
9 - HEAVY OIL	0	0	0	0.0%
10 - LIGHT OIL	72,848	3,125	69,723	2,231.1%
11 - COAL	9,718,456	11,858,055	(2,139,599)	(18.0%)
12 - GAS	25,227,323	23,858,422	1,368,901	5.7%
13 - NUCLEAR	0	0	0	0.0%
14	0	0	0	0.0%
15	0	0	0	0.0%
16 - TOTAL (MWH)	35,018,627	35,719,602	(700,975)	(2.0%)
UNITS OF FUEL BURNED				
17 - HEAVY OIL (BBL)	0	0	0	0.0%
18 - LIGHT OIL (BBL)	162,382	33,179	129,203	389.4%
19 - COAL (TON)	4,425,252	5,325,962	(900,710)	(16.9%)
20 - GAS (MCF)	198,464,799	182,938,293	15,526,506	8.5%
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	927,656	192,302	735,354	382.4%
26 - COAL	102,196,707	123,887,171	(21,690,464)	(17.5%)
27 - GAS	203,148,563	182,938,293	20,161,876	11.0%
28 - NUCLEAR	0	0	0	0.0%
29	0	0	0	0.0%
30	0	0	0	0.0%
31 - TOTAL (MILLION BTU)	306,224,533	307,017,766	(793,233)	(0.3%)

A-3 Generating System Comparative Data Report

Duke Energy Florida

Docket No. 160001-EI
Witness: Menendez
Exhibit No. (CAM-3T)
Schedule: A3-2
Sheet 6 of 9

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	0.01	0.2	2280.3%
34 - COAL	27.8	33.20	(5.4)	(16.3%)
35 - GAS	72.0	66.79	5.2	7.8%
36 - NUCLEAR	0.0	0.00	0.0	0.0%
37	0.0	0.00	0.0	0.0%
38	0.0	0.00	0.0	0.0%
39 - TOTAL (% MWH)	100.0	100.0	0.0	0.0%
FUEL COST PER UNIT ($)				
40 - HEAVY OIL ($/BBL)	0.00	0.00	0.00	0.0%
41 - LIGHT OIL ($/BBL)	127.40	126.95	0.45	0.4%
42 - COAL ($/TON)	85.86	82.23	3.63	4.4%
43 - GAS ($/MCF)	4.78	5.51	(0.74)	(13.3%)
44 - NUCLEAR ($/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 ($/MILLION BTU)				
47 - HEAVY OIL	0.00	0.00	0.00	0.0%
48 - LIGHT OIL	22.30	21.90	0.40	1.8%
49 - COAL	3.72	3.54	0.18	5.2%
50 - GAS	4.67	5.51	(0.84)	(15.3%)
51 - NUCLEAR	0.00	0.00	0.00	0.0%
52	0.00	0.00	0.00	0.0%
53	0.00	0.00	0.00	0.0%
54 - SYSTEM ($/MBTU)	4.40	4.72	(0.32)	(6.8%)
BTU BURNED PER KWH (BTU/KWH)				
55 - HEAVY OIL	0	0	0	0.0%
56 - LIGHT OIL	12,734	61,537	(48,803)	(79.3%)
57 - COAL	10,516	10,448	68	0.7%
58 - GAS	8,051	7,668	383	5.0%
59 - NUCLEAR	0	0	0	0.0%
60	0	0	0	0.0%
61	0	0	0	0.0%
62 - SYSTEM (BTU/KWH)	8,745	8,595	149	1.7%

A-3 Generating System Comparative Data Report

Duke Energy Florida

Docket No. 160001-EI
Witness: Menendez
Exhibit No. (CAM-3T)
Schedule: A3-3
Sheet 7 of 9

FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
GENERATED FUEL COST PER KWH (CENTS/KWH)				
63 - HEAVY OIL	0.00	0.00	0.00	0.0%
64 - LIGHT OIL	28.40	134.78	(106.38)	(78.9%)
65 - COAL	3.91	3.69	0.22	5.9%
66 - GAS	3.76	4.23	(0.47)	(11.1%)
67 - NUCLEAR	0.00	0.00	0.00	0.0%
68	0.00	0.00	0.00	0.0%
69	0.00	0.00	0.00	0.0%
70 - SYSTEM (CENTS/KWH)	3.85	4.06	(0.21)	(5.2%)

Duke Energy Florida
Schedule A6
Power Sold for the Month of
December 2015

Docket No. 160001-EI
Witness: Menendez
Exhibit No. (CAM-3T)
Schedule A6
Sheet 8 of 9

(1)	(2)	(3)	(4)	(5)	(6a)	(6b)	(7)	(8)	(9)
Sold To	**Type & Schedule**	**Total KWH Sold (000)**	**KWH Wheeled from Other Systems (000)**	**KWH from Own Generation (000)**	**Fuel Cost C/KWH**	**Total Cost C/KWH**	**Fuel Adj Total $**	**Total Cost $**	**Gain on Sales $**
ESTIMATED		4,380			3.123	3.810	136,796.00	166,891.00	30,095.00
ACTUAL									
Exelon Generation Company, LLC	InternationalSwapsDe	175		175	2.335	2.584	4,086.70	4,522.15	435.45
Florida Power & Light Company	CR-1	600		600	2.445	2.968	14,670.81	17,806.20	3,135.39
PJM Settlements, Inc	MR1	1,297		1,297	2.001	2.078	25,954.97	26,953.43	998.46
Reedy Creek Improvement District	CR-1	1,750		1,750	1.784	2.491	31,227.45	43,591.05	12,363.60
Reedy Creek Improvement District	Schedule C	45		45	2.093	2.792	941.85	1,256.30	314.45
The Energy Authority	EEI	40		40	1.060	1.349	423.94	539.78	115.84
The Energy Authority	Schedule OS	595		595	2.204	2.842	13,113.59	16,910.10	3,796.51
Subtotal - Gain on Other Power Sales		**4,502**		**4,502**	**2.008**	**2.478**	**90,419.31**	**111,579.01**	**21,159.70**
CURRENT MONTH TOTAL		4,502		4,502	2.01	2.48	90,419.31	111,579.01	21,159.70
DIFFERENCE		122		4,502	(1.11)	(1.33)	(46,376.69)	(55,311.99)	(8,935.30)
DIFFERENCE %		3		-	(35.69)	(34.95)	(33.90)	(33.14)	(29.69)
CUMULATIVE ACTUAL		193,138		193,138	3.01	4.94	5,814,590.94	9,535,245.72	3,720,654.78
CUMULATIVE ESTIMATED		126,300		121,920	3.32	4.06	4,199,152.00	5,122,965.00	923,813.00
DIFFERENCE		66,838		71,218	(0.31)	0.88	1,615,438.94	4,412,280.72	2,796,841.78
DIFFERENCE %		53		58	(9.45)	21.72	38.47	86.13	302.75

DUKE ENERGY FLORIDA
SCHEDULE A12 - CAPACITY COSTS
FOR THE PERIOD JAN - DEC 2015

Docket No. 160001-EI
Witness: Menendez
Exhibit No. (CAM-3T)
Schedule A12
Sheet 9 of 9

	Counterparty	Type	MW	Start Date - End Date	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YTD
1	Orange Cogen (ORANGECO)	QF	74.00	7/1/95 - 12/31/24	3,108,487	3,266,545	3,266,545	3,266,545	3,266,545	3,266,545	3,266,545	3,266,545	3,266,545	3,266,545	3,266,545	3,266,545	39,040,487
2	Orlando Cogen Limited (ORLACOGL)	QF	79.20	9/1/93 - 12/31/23	4,390,316	4,602,317	4,594,986	4,491,065	4,619,448	4,619,448	4,619,448	4,619,448	4,619,448	4,619,448	4,619,448	(4,170,709)	46,244,108
3	Pasco County Resource Recovery (PASCOUNT)	QF	23.00	1/1/95 - 12/31/24	1,483,270	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	18,836,540
4	Pinellas County Resource Recovery (PINCOUNT)	QF	54.75	1/1/95 - 12/31/24	3,530,828	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	44,839,155
5	Polk Power Partners, L.P. (MULBERRY)	QF	115.00	8/1/94 - 8/8/24	5,999,259	6,306,018	6,306,018	6,306,018	6,306,018	6,287,309	6,306,018	6,306,018	6,306,018	6,306,018	6,306,018	6,306,018	75,346,748
6	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	QF	39.60	8/1/94 - 12/31/23	661,873	698,574	715,513	729,448	741,070	754,330	717,450	677,120	665,502	655,232	623,134	622,230	8,261,478
7	Southern purchase - Scherer	Other	74	6/1/10 - 5/31/16	1,750,402	1,787,399	1,756,170	1,757,178	1,824,402	3,375,058	1,767,776	1,767,514	1,767,518	1,765,673	1,765,484	1,765,673	22,850,249
8	Southern purchase - Franklin	Other	350	6/1/10 - 5/31/16	3,119,543	3,290,615	3,174,459	3,182,635	3,179,430	2,251,554	3,181,573	3,180,294	3,504,765	3,171,307	3,170,383	3,171,307	37,577,865
9	Retail Wheeling				(44,982)	(109,006)	(31,099)	(4,143)	(42,143)	(19,211)	(10,188)	(49,327)	(24,634)	(9,153)	(30,188)	(20,424)	(394,498)
10	Levy Projected Expense				9,215,650	9,145,040	9,074,430	9,003,820	0	0	0	0	0	0	0	0	36,438,940
11	CR-3 Projected Expense				5,442,716	5,412,634	5,382,366	5,352,099	5,321,833	5,291,141	5,260,871	5,208,780	5,178,331	5,148,065	5,117,797	5,087,530	63,204,163
	SUBTOTAL				38,657,362	39,733,009	39,572,261	39,417,539	30,549,476	31,159,046	30,442,366	30,309,265	30,616,365	30,256,007	30,171,494	21,361,044	392,245,234
	Purchases/Sales (Net)	Other	**MW**	**Contracts**													
	Chattahoochee Capacity Purchase		5.25	1/1/03-1/31/17	0	0	0	0	0	0	0	0	0	0	0	0	0
	Vandolah Capacity - Northern Star		655	6/1/12-5/31/27	2,932,374	2,895,800	1,886,774	1,947,064	2,800,877	5,785,668	5,780,497	5,715,411	2,715,406	1,919,503	2,016,937	2,947,051	39,343,362
	Schedule H Capacity Sales-NSB		-1	on-going no term date	(14,792)	(14,792)	(14,792)	(14,792)	(16,080)	(16,080)	0	0	0	0	0	0	(91,328)
	Shady Hills Tolling		517	4/1/07-4/30/24	1,410,076	1,646,992	1,406,900	1,440,840	1,912,680	3,888,000	3,888,000	3,886,445	1,814,400	1,366,200	1,366,200	1,941,646	25,968,379
	Calpine Osprey		515	Oct 2014 to Dec 2016	1,405,950	1,465,539	1,443,650	1,443,650	1,443,650	1,443,650	1,443,650	1,443,650	1,443,650	1,443,650	1,443,650	1,443,650	17,307,989
	Total		1691.25		5,733,608	5,993,540	4,722,532	4,816,761	6,141,127	11,101,238	11,112,147	11,045,506	5,973,456	4,729,353	4,826,787	6,332,347	82,528,402
	TOTAL				44,390,970	45,726,549	44,294,793	44,234,300	36,690,604	42,260,284	41,554,513	41,354,770	36,589,821	34,985,360	34,998,281	27,693,391	474,773,637

Capital Structure and Cost Rates Applied to Capital Projects
Duke Energy Florida
Estimated for the Period of : January through June 2015

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost
Common Equity	$ 4,101,842	48.36%	10.50%	5.08%
Preferred Stock	-	0.00%	0.00%	0.00%
Long Term Debt	3,174,547	37.42%	5.22%	1.95%
Short Term Debt	79,303	0.93%	1.22%	0.01%
Customer Deposits - Active	157,817	1.86%	2.25%	0.04%
Customer Deposits - Inactive	1,181	0.01%	0.00%	0.00%
Deferred Tax	1,114,885	13.14%	0.00%	0.00%
Deferred Tax (FAS 109)	(148,097)	-1.75%	0.00%	0.00%
ITC	1,246	0.01%	0.00%	0.00%
	8,482,724	88.34%		7.08%

Total Debt	2.00%
Total Equity	5.08%

* May 2014 DEF Surveillance Report capital structure and cost rates.
* Reference: Docket Nos. 120001-EG, 120002-EI, 120007-EI, PSC Order No. 12-0425-PAA-EU, page 8
* Included for Informational purposes only. DEF 2015 Actual True-up Filing does not currently include a capital return component

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 5
PARTY: DUKE ENERGY FLORIDA, LLC – (DIRECT)
DESCRIPTION: Christopher A. Menendez CAM-4T

Capital Structure and Cost Rates Applied to Capital Projects
Duke Energy Florida
Estimated for the Period of : July through December 2015

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost
Common Equity	$ 4,681,853	48.76%	10.50%	5.12%
Preferred Stock	-	0.00%	0.00%	0.00%
Long Term Debt	3,672,596	38.25%	5.19%	1.98%
Short Term Debt	(90,568)	-0.94%	0.17%	0.00%
Customer Deposits - Active	182,163	1.90%	2.31%	0.04%
Customer Deposits - Inactive	1,306	0.01%	0.00%	0.00%
Deferred Tax	1,318,615	13.73%	0.00%	0.00%
Deferred Tax (FAS 109)	(164,391)	-1.71%	0.00%	0.00%
ITC	498	0.01%	0.00%	0.00%
	9,602,073	100.00%		7.15%

Total Debt	2.03%
Total Equity	5.12%

* May 2015 DEF Surveillance Report capital structure and cost rates.
* Reference: Docket Nos. 120001-EG, 120002-EI, 120007-EI, PSC Order No. 12-0425-PAA-EU, page 8
* Included for Informational purposes only. DEF 2015 Actual True-up Filing does not currently include a capital return component

Docket 160001-EI
Exhibit No. ____(CAM-2)
Part 1

DUKE ENERGY FLORIDA

FUEL COST RECOVERY

ESTIMATED / ACTUAL TRUE-UP

JANUARY THROUGH DECEMBER 2016

Schedule E1-B – Calculation of Estimated True-up

Schedule RRSSA – Summary of RRSSA Adjustments

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: 160001-EI EXHIBIT: 6
PARTY: DUKE ENERGY FLORIDA, LLC – (DIRECT)
DESCRIPTION: Christopher A. Menendez CAM-2

CALCULATION OF ESTIMATED TRUE-UP
(6 MONTHS ACTUAL, 6 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2016

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 94,981,804	$ 83,413,721	$ 78,345,839	$ 82,817,723	$ 90,802,680	$ 110,507,482	$ 540,869,249
	2	Fuel Cost of Power Sold	(2,691,656)	(1,345,614)	(1,423,831)	(2,132,788)	(1,895,385)	(4,198,390)	(13,687,665)
	3	Fuel Cost of Purchased Power	4,937,035	6,217,173	14,421,739	20,084,233	32,818,134	31,608,698	110,087,011
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	8,284,310	9,432,944	9,730,163	7,658,173	10,499,028	10,232,952	55,837,571
	4	Energy Cost of Economy Purchases	216,014	(55,757)	265,606	390,715	406,645	1,004,737	2,227,961
	5	Adjustments to Fuel Cost	(24,885)	(26,759)	(31,140)	(30,128)	32,448	(21,508)	(101,972)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	105,702,622	97,635,708	101,308,376	108,787,927	132,663,550	149,133,972	695,232,155
B	1	Jurisdictional MWH Sales	2,772,355	2,712,018	2,687,916	2,710,583	3,189,901	3,609,509	17,682,282
	2	Non-Jurisdictional MWH Sales	30,873	20,634	21,753	74,556	23,060	28,457	199,333
	3	TOTAL SALES (Lines B1 + B2)	2,803,228	2,732,653	2,709,669	2,785,139	3,212,961	3,637,966	17,881,616
	4	Jurisdictional % of Total Sales (Line B1/B3)	98.90%	99.24%	99.20%	97.32%	99.28%	99.22%	98.89%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	98,935,994	97,150,007	94,743,489	78,832,246	94,121,778	108,162,345	571,945,858
	1a	RRSSA Refund - $60M	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	30,000,000
	1b	RRSSA Fuel Adjustment	-	-	-	-	-	-	-
	1c	RRSSA Refund - $10M	833,333	833,333	833,333	833,333	833,333	833,333	5,000,000
	2	True-Up Provision	6,560,919	6,560,919	6,560,919	10,764,480	10,764,480	10,764,480	51,976,199
	2a	Incentive Provision	717,816	717,816	717,816	717,816	717,816	717,816	4,306,896
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	112,048,062	110,262,076	107,855,558	96,147,876	111,437,408	125,477,974	663,228,953
	4	Fuel & Net Power Transactions (Line A6)	105,702,622	97,635,708	101,308,376	108,787,927	132,663,550	149,133,972	695,232,155
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	104,594,254	96,944,061	100,538,108	105,914,760	131,761,056	148,029,915	687,782,154
	6	Over/(Under) Recovery (Line C3 - Line C5)	7,453,809	13,318,014	7,317,449	(9,766,884)	(20,323,648)	(22,551,941)	(24,553,201)
	7	Interest Provision	38,614	41,097	44,882	37,893	25,826	17,633	205,945
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	7,492,423	13,359,111	7,362,331	(9,728,990)	(20,297,822)	(22,534,308)	(24,347,255)
	9	Plus: Prior Period Balance	116,563,080	116,563,080	116,563,080	116,563,080	116,563,080	116,563,080	116,563,080
	10	Plus: Cumulative True-Up Provision	(6,560,919)	(13,121,839)	(19,682,758)	(30,447,238)	(41,211,719)	(51,976,199)	(51,976,199)
	11	Subtotal Prior Period True-up	110,002,161	103,441,241	96,880,322	86,115,842	75,351,361	64,586,881	64,586,881
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	$117,494,583	124,292,775	$125,094,187	$104,600,716	$73,538,414	$40,239,626	40,239,626

CALCULATION OF ESTIMATED TRUE-UP
(6 MONTHS ACTUAL, 6 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2016

			JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 104,953,817	$ 107,346,359	$ 104,419,313	$ 98,063,519	$ 83,543,398	$ 92,467,952	$ 1,131,663,607
	2	Fuel Cost of Power Sold	(2,540,491)	(2,584,887)	(2,111,545)	(1,805,691)	(1,522,351)	(1,698,236)	(25,950,865)
	3	Fuel Cost of Purchased Power	20,235,740	20,086,620	17,363,635	11,608,789	7,945,939	4,274,978	191,602,712
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	11,644,372	11,687,183	10,720,507	9,892,299	11,332,121	12,008,298	123,122,350
	4	Energy Cost of Economy Purchases	285,457	315,966	252,602	470,078	462,356	268,909	4,283,329
	5	Adjustments to Fuel Cost	(4,357,619)	(20,508)	(18,630)	(16,142)	(12,413)	2,316	(4,524,968)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	130,221,276	136,830,734	130,625,882	118,212,851	101,749,050	107,324,217	1,420,196,164
B	1	Jurisdictional MWH Sales	3,746,390	3,802,397	3,818,043	3,520,143	2,939,053	2,841,931	38,350,239
	2	Non-Jurisdictional MWH Sales	22,211	24,219	21,223	18,003	12,892	17,383	315,264
	3	TOTAL SALES (Lines B1 + B2)	3,768,601	3,826,616	3,839,266	3,538,146	2,951,945	2,859,314	38,665,503
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.41%	99.37%	99.45%	99.49%	99.56%	99.39%	99.18%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	111,627,849	113,309,102	113,778,746	104,836,277	87,392,895	84,477,439	1,187,368,166
	1a	RRSSA Refund - $60M	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	60,000,000
	1b	RRSSA Fuel Adjustment	-	-	-	-	-	-	-
	1c	RRSSA Refund - $10M	833,333	833,333	833,333	833,333	833,333	833,333	10,000,000
	2	True-Up Provision	10,764,480	10,764,480	10,764,480	10,764,480	10,764,480	10,790,295	116,588,896
	2a	Incentive Provision	717,816	717,816	717,816	717,816	717,816	717,821	8,613,797
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	128,943,479	130,624,732	131,094,376	122,151,906	104,708,525	101,818,889	1,382,570,859
	4	Fuel & Net Power Transactions (Line A6)	130,221,276	136,830,734	130,625,882	118,212,851	101,749,050	107,324,217	1,420,196,164
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	129,504,751	136,023,087	129,959,403	117,657,009	101,341,875	106,712,207	1,408,980,487
	6	Over/(Under) Recovery (Line C3 - Line C5)	(561,273)	(5,398,356)	1,134,973	4,494,897	3,366,650	(4,893,319)	(26,409,628)
	7	Interest Provision	10,719	6,461	2,466	2	(2,116)	(5,695)	217,781
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(550,554)	(5,391,894)	1,137,438	4,494,899	3,364,533	(4,899,014)	(26,191,847)
	9	Plus: Prior Period Balance	116,563,080	116,563,080	116,563,080	116,563,080	116,563,080	116,563,080	116,563,080
	10	Plus: Cumulative True-Up Provision	(62,740,679)	(73,505,160)	(84,269,640)	(95,034,120)	(105,798,601)	(116,588,896)	(116,588,896)
	11	Subtotal Prior Period True-up	53,822,401	43,057,920	32,293,440	21,528,960	10,764,479	(25,816)	(25,816)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	$28,924,591	$12,768,217	$3,141,175	($3,128,407)	($10,528,354)	($26,217,663)	($26,217,663)

Docket No. 160001-EI
Exhibit CAM-2, Part 1
Schedule E1-B-1

COMPARISON OF ESTIMATED/ACTUAL VERSUS MIDCOURSE PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
Duke Energy Florida
Estimated for the Period of : January through December 2016

		DOLLARS				MWH				c/KWH			
		ESTIMATED/ ACTUAL	MIDCOURSE FILING	DIFFERENCE AMOUNT	DIFFERENCE %	ESTIMATED/ ACTUAL	MIDCOURSE FILING	DIFFERENCE AMOUNT	DIFFERENCE %	ESTIMATED/ ACTUAL	MIDCOURSE FILING	DIFFERENCE AMOUNT	DIFFERENCE %
1	Fuel Cost of System Net Generation (E3)	1,131,663,607	1,136,982,595	(5,318,988)	0%	33,747,272	34,134,015	(386,743)	-1%	3.353	3.331	0.022	1%
2	Spent Nuclear Fuel Disposal Cost	0	0	-	0%			-	0%	0.000	0.000	0.000	0%
3	Coal Car Investment	0	0	-	0%			-	0%	0.000	0.000	0.000	0%
4	Adjustment to Fuel Cost	(4,524,968)	(124,894)	(4,400,074)	0%			-	0%	0.000	0.000	0.000	0%
5	TOTAL COST OF GENERATED POWER	1,127,138,639	1,136,857,701	(9,719,062)	-1%	33,747,272	34,134,015	(386,743)	-1%	3.340	3.331	0.009	0%
6	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)	191,602,712	140,939,225	50,663,487	36%	5,316,530	3,841,283	1,475,246	38%	3.604	3.669	-0.065	-2%
7	Energy Cost of Economy Purchases (E9)	4,283,329	4,001,682	281,647	7%	96,026	84,439	11,588	14%	4.461	4.739	-0.279	-6%
8	Payments to Qualifying Facilities (E8)	123,122,350	142,117,899	(18,995,549)	-13%	3,138,818	3,382,599	(243,781)	-7%	3.923	4.201	-0.279	-7%
9	TOTAL COST OF PURCHASED POWER	319,008,391	287,058,806	31,949,585	11%	8,551,373	7,308,321	1,243,053	17%	3.730	3.928	-0.197	-5%
10	TOTAL AVAILABLE MWH (LINE 5 + LINE 9)			-		42,298,645	41,442,335	856,310	2%	0.000	0.000	0.000	0%
11	Fuel Cost of Economy Sales (E6)	(2,348,752)	(4,542,044)	2,193,292	-48%	(89,367)	(169,685)	80,318	-47%	2.628	2.677	-0.049	-2%
11a	Gain on Economy Sales (E6)	(585,247)	(1,041,152)	455,905	-44%	(89,367)	(169,685)	80,318	-47%	0.655	0.614	0.041	7%
11b	Gain on Economy Sales -20% (E6)	0	0	-	0%								
12	Fuel Cost of Stratified Sales (E6)	(23,016,866)	(20,139,925)	(2,876,941)	14%	(1,199,020)	(848,435)	(350,585)	41%	1.920	2.374	-0.454	-19%
13	TOTAL FUEL COST AND GAINS OF POWER SALES (LINES 11 + 11a + 12)	(25,950,865)	(25,723,121)	(227,744)	1%	(1,288,387)	(1,018,120)	(270,267)	27%	2.014	2.527	-0.512	-20%
14	Net Inadvertent Interchange					76,555		76,555					
15	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 9 + 13 + 14)	1,420,196,164	1,398,193,386	22,002,779	2%	41,086,813	40,424,215	662,598	2%	3.457	3.459	-0.002	0%
16	Net Unbilled					(79,198)	(25,549)	(53,649)	210%	0.000	0.000	0.000	0%
17	Company Use					(154,278)	(144,000)	(10,278)	7%	0.000	0.000	0.000	0%
18	T & D Losses					(2,187,835)	(2,024,254)	(163,581)	8%	0.000	0.000	0.000	0%
19	SYSTEM MWH SALES	1,420,196,164	1,398,193,386	22,002,779	2%	38,665,503	38,230,412	435,091	1%	3.673	3.657	0.016	0%
20	Wholesale MWH Sales	(11,803,207)	(7,947,702)	(3,855,504)	49%	(315,264)	(215,930)	(99,334)	46%	3.744	3.681	0.063	2%
21	Jurisdictional MWH Sales	1,408,392,958	1,390,245,683	18,147,274	1%	38,350,239	38,014,482	335,757	1%	3.672	3.657	0.015	0%
21a	Jurisdictional Loss Multiplier	1.0004	1.00052	(0)	0%	1.0004	1.00052	(0)	0%				
22	Jurisdictional Sales Adjusted for Line Losses	1,408,980,486	1,390,968,611	18,011,875	1%	38,350,239	38,014,482	335,757	1%	3.674	3.659	0.015	0%
23	TRUE-UP **	(116,563,080)	(116,588,895)	25,815	0%	38,350,239	38,014,482	335,757	1%	(0.304)	(0.307)	0.003	-1%
24	TOTAL JURISDICTIONAL FUEL COST	1,292,417,405	1,274,379,716	18,037,689	1%	38,350,239	38,014,482	335,757	1%	3.370	3.352	0.018	1%
25	Revenue Tax Factor	930,541	917,553	12,987	1%								
26	Fuel Factor Adjusted for Taxes	1,293,347,945	1,275,297,269	18,050,676	1%	38,350,239	38,014,482	335,757	1%	3.372	3.355	0.018	1%
27	GPIF **	(8,613,797)	(8,613,797)	-	0%	38,350,239	38,014,482	335,757	1%	(0.022)	(0.023)	0.000	-1%
28	Fuel Factor Adjusted for Taxes Including GPIF	1,284,734,148	1,266,683,472	18,050,676	1%	38,350,239	38,014,482	335,757	1%	3.350	3.332	0.018	1%
29	FUEL FACTOR ROUNDED TO NEAREST .001 c/KWH									3.350	3.332	0.018	1%

* Included for Informational Purposes Only

** Calculation Based on Jurisdictional MWH Sales

Docket: 160001-EI
Exhibit: CAM-2, Part 1
Schedule: RRSSA

Duke Energy Florida
Summary of Revised and Restated Settlement Agreement (RRSSA) Adjustments
Estimated for the Period of January through December 2016

	Retail:	Actual Jan-16	Actual Feb-16	Actual Mar-16	Actual Apr-16	Actual May-16	Actual Jun-16	Estimated Jul-16	Estimated Aug-16	Estimated Sep-16	Estimated Oct-16	Estimated Nov-16	Estimated Dec-16	12 Month Period	Schedule Reference	RRSSA Paragraph
1	RRSSA Refund ($60 million)	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	60,000,000	E1-B, line C1a	6.b.
2	RRSSA Refund ($10 million)	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	10,000,000	E1-B, line C1c	6.a.
3	Total RRSSA Refunds (Lines 1 + 2)	5,833,333	5,833,333	5,833,333	5,833,333	5,833,333	5,833,333	5,833,333	5,833,333	5,833,333	5,833,333	5,833,333	5,833,333	70,000,000		

Docket No. 160001-EI
Exhibit CAM-2, Part 1
Schedule E2

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January through December 2016

			Actual Jan-16	Actual Feb-16	Actual Mar-16	Actual Apr-16	Actual May-16	Actual Jun-16	Estimated Jul-16	Estimated Aug-16	Estimated Sep-16	Estimated Oct-16	Estimated Nov-16	Estimated Dec-16	TOTAL
1	Fuel Cost of System Net Generation		$94,981,804	$83,413,721	$78,345,839	$82,817,723	$90,802,680	$110,507,482	$104,953,817	$107,346,359	$104,419,313	$98,063,519	$83,543,398	$92,467,952	$1,131,663,607
1a	Nuclear Fuel Disposal Cost		0	0	0	0	0	0	0	0	0	0	0	0	0
1b	Adjustments to Fuel Cost		(24,885)	(26,759)	(31,140)	(30,128)	32,448	(21,508)	(4,357,619)	(20,508)	(18,630)	(16,142)	(12,413)	2,316	(4,524,968)
2	Fuel Cost of Power Sold		(308,216)	(43,732)	(219,326)	(444,872)	(13,586)	(577)	(305,124)	(276,610)	(111,035)	(106,787)	(356,771)	(162,116)	(2,348,752)
2a	Gains on Power Sales		(120,066)	(18,437)	16,138	(159,385)	17,392	29	(74,269)	(67,329)	(27,027)	(25,992)	(86,840)	(39,460)	(585,247)
2b	Fuel Cost of Stratified Sales		(2,263,375)	(1,283,444)	(1,220,643)	(1,528,531)	(1,899,190)	(4,197,841)	(2,161,098)	(2,240,948)	(1,973,483)	(1,672,912)	(1,078,740)	(1,496,660)	(23,016,866)
3	Fuel Cost of Purchased Power (Excl Economy)		4,937,035	6,217,173	14,421,739	20,084,233	32,818,134	31,608,698	20,235,740	20,086,620	17,363,635	11,608,789	7,945,939	4,274,978	191,602,712
3a	Energy Payments to Qualifying Facilities		8,284,310	9,432,944	9,730,163	7,658,173	10,499,028	10,232,952	11,644,372	11,687,183	10,720,507	9,892,299	11,332,121	12,008,298	123,122,350
4	Energy Cost of Economy Purchases		216,014	(55,757)	265,606	390,715	406,645	1,004,737	285,457	315,966	252,602	470,078	462,356	268,909	4,283,329
5	Total System Fuel & Net Power Transactions		$105,702,622	$97,635,708	$101,308,376	$108,787,927	$132,663,550	$149,133,972	$130,221,276	$136,830,734	$130,625,882	$118,212,851	$101,749,050	$107,324,217	$1,420,196,164
6	Jurisdictional MWH Sold		2,772,355	2,712,018	2,687,916	2,710,583	3,189,901	3,609,509	3,746,390	3,802,397	3,818,043	3,520,143	2,939,053	2,841,931	38,350,239
7	Jurisdictional % of Total Sales		98.90%	99.24%	99.20%	97.32%	99.28%	99.22%	99.41%	99.37%	99.45%	99.49%	99.56%	99.39%	99.18%
8	Jurisdicitonal Fuel & Net Power Transactions		104,539,893	96,893,677	100,497,909	105,872,411	131,708,373	147,970,727	129,452,970	135,968,700	129,907,440	117,609,965	101,301,354	106,669,539	1,408,392,958
9	Jurisdictional Loss Multiplier		1.00052	1.00052	1.00040	1.00040	1.00040	1.00040	1.00040	1.00040	1.00040	1.00040	1.00040	1.00040	1.00040
10	Jurisdictional Fuel & Net Power Transactions		104,594,254	96,944,061	100,538,108	105,914,760	131,761,056	148,029,915	129,504,751	136,023,087	129,959,403	117,657,009	101,341,875	106,712,207	1,408,980,487
11	Adjusted System Sales	MWH	2,803,228	2,732,653	2,709,669	2,785,139	3,212,961	3,637,966	3,768,601	3,826,616	3,839,266	3,538,146	2,951,945	2,859,314	38,665,503
12	System Cost per MWH Sold	c/kwh	3.7708	3.5729	3.7388	3.9059	4.1291	4.0994	3.4554	3.5758	3.4024	3.3411	3.4468	3.7535	3.6730
13	Jurisdictional Loss Multiplier	x	1.00052	1.00052	1.0004	1.0004	1.0004	1.0004	1.0004	1.0004	1.0004	1.0004	1.0004	1.0004	1.00040
14	Jurisdictional Cost per MWH Sold	c/kwh	3.7728	3.5746	3.7404	3.9075	4.1306	4.1011	3.4568	3.5773	3.4038	3.3424	3.4481	3.7549	3.6740
15	Prior Period True-Up	+	-0.2367	-0.2419	-0.2441	-0.3971	-0.3375	-0.2982	-0.2873	-0.2831	-0.2819	-0.3058	-0.3663	-0.3788	-0.3039
16	Total Jurisdictional Fuel Expense	c/kwh	3.5361	3.3327	3.4963	3.5103	3.7931	3.8029	3.1695	3.2942	3.1219	3.0366	3.0819	3.3761	3.3700
17	Revenue Tax Multiplier	x	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
18	Recovery Factor Adjusted for Taxes	c/kwh	3.5386	3.3351	3.4988	3.5128	3.7958	3.8056	3.1717	3.2966	3.1241	3.0388	3.0841	3.3786	3.3725
19	GPIF	+	-0.0259	-0.0265	-0.0267	-0.0265	-0.0225	-0.0199	-0.0192	-0.0189	-0.0188	-0.0204	-0.0244	-0.0253	-0.0225
20	Total Recovery Factor (rounded .001)	c/kwh	3.513	3.309	3.472	3.486	3.773	3.786	3.153	3.278	3.105	3.018	3.060	3.353	3.350

Duke Energy Florida

Generating System Comparative Data by Fuel Type

Estimated for the Period of : January through December 2016

			Actual Jan-16	Actual Feb-16	Actual Mar-16	Actual Apr-16	Actual May-16	Actual Jun-16	Subtotal
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		0	0	0	0	0	0	0
2	LIGHT OIL		1,106,067	613,795	1,563,581	906,310	1,391,758	3,814,995	9,396,506
3	COAL		24,059,366	18,210,138	15,519,123	25,215,560	26,515,970	38,453,893	147,974,050
4	GAS		69,816,371	64,589,789	61,263,135	56,695,852	62,894,953	68,238,594	383,498,693
5	NUCLEAR		0	0	0	0	0	0	0
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	94,981,804	83,413,721	78,345,839	82,817,723	90,802,680	110,507,482	540,869,249
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		0	0	0	0	0	0	0
9	LIGHT OIL		4,146	1,841	5,935	3,609	5,428	15,993	36,953
10	COAL		600,135	461,509	389,073	686,155	650,012	994,705	3,781,588
11	GAS		2,172,779	1,981,387	1,956,708	1,734,448	1,830,729	2,048,239	11,724,290
12	NUCLEAR		0	0	0	0	0	0	0
13	SOLAR		0	0	0	0	0	200	200
14	OTHER		0	0	0	0	0	0	0
15	TOTAL	MWH	2,777,060	2,444,736	2,351,716	2,424,213	2,486,169	3,059,137	15,543,031
	UNITS OF FUEL BURNED								
16	HEAVY OIL	BBL	0	0	0	0	0	0	0
17	LIGHT OIL	BBL	8,322	4,612	12,546	7,501	12,418	37,207	82,606
18	COAL	TON	296,581	229,237	189,735	321,898	323,704	469,552	1,830,707
19	GAS	MCF	16,262,865	14,951,085	15,536,706	14,358,141	16,750,343	17,662,903	95,522,043
20	NUCLEAR	MMBTU	0	0	0	0	0	0	0
21	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
22	HEAVY OIL		0	0	0	0	0	0	0
23	LIGHT OIL		47,930	26,527	72,455	43,254	71,451	214,270	475,887
24	COAL		6,774,971	5,145,573	4,253,901	7,236,086	7,325,271	10,505,233	41,241,035
25	GAS		16,637,107	15,307,929	15,894,591	14,678,467	17,065,141	17,979,455	97,562,688
26	NUCLEAR		0	0	0	0	0	0	0
27	OTHER		0	0	0	0	0	0	0
28	TOTAL	MMBTU	23,460,008	20,480,028	20,220,947	21,957,807	24,461,863	28,698,958	139,279,611
	GENERATION MIX (% MWH)								
29	HEAVY OIL		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
30	LIGHT OIL		0.15%	0.08%	0.25%	0.15%	0.22%	0.52%	0.24%
31	COAL		21.61%	18.88%	16.54%	28.30%	26.15%	32.52%	24.33%
32	GAS		78.24%	81.05%	83.20%	71.55%	73.64%	66.96%	75.43%
33	NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	SOLAR		0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%
35	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
36	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
37	HEAVY OIL	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
38	LIGHT OIL	$/BBL	132.91	133.09	124.63	120.83	112.08	102.53	113.75
39	COAL	$/TON	81.12	79.44	81.79	78.33	81.91	81.89	80.83
40	GAS	$/MCF	4.29	4.32	3.94	3.95	3.75	3.86	4.01
41	NUCLEAR	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
43	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	LIGHT OIL		23.08	23.14	21.58	20.95	19.48	17.81	19.75
45	COAL		3.55	3.54	3.65	3.49	3.62	3.66	3.59
46	GAS		4.20	4.22	3.85	3.86	3.69	3.80	3.93
47	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
48	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
49	TOTAL	$/MMBTU	4.05	4.07	3.87	3.77	3.71	3.85	3.88
	BTU BURNED PER KWH (BTU/KWH)								
50	HEAVY OIL		0	0	0	0	0	0	0
51	LIGHT OIL		11,561	14,408	12,208	11,983	13,163	13,398	12,878
52	COAL		11,289	11,149	10,933	10,546	11,269	10,561	10,906
53	GAS		7,657	7,726	8,123	8,463	9,322	8,778	8,321
54	NUCLEAR		0	0	0	0	0	0	0
55	OTHER		0	0	0	0	0	0	0
56	TOTAL	BTU/KWH	8,448	8,377	8,598	9,058	9,839	9,381	8,961
	GENERATED FUEL COST PER KWH (C/KWH)								
57	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	LIGHT OIL		26.68	33.34	26.34	25.11	25.64	23.85	25.43
59	COAL		4.01	3.95	3.99	3.67	4.08	3.87	3.91
60	GAS		3.21	3.26	3.13	3.27	3.44	3.33	3.27
61	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
62	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
63	TOTAL	C/KWH	3.42	3.41	3.33	3.42	3.65	3.61	3.48

Duke Energy Florida

Generating System Comparative Data by Fuel Type

Estimated for the Period of : January through December 2016

			Estimated Jul-16	Estimated Aug-16	Estimated Sep-16	Estimated Oct-16	Estimated Nov-16	Estimated Dec-16	Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		0	0	0	0	0	0	0
2	LIGHT OIL		330,446	305,453	275,926	288,695	241,215	273,786	11,112,027
3	COAL		27,744,275	29,935,725	28,319,546	26,424,233	25,490,345	28,549,413	314,437,587
4	GAS		76,879,096	77,105,181	75,823,841	71,350,591	57,811,838	63,644,753	806,113,993
5	NUCLEAR		0	0	0	0	0	0	0
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	104,953,817	107,346,359	104,419,313	98,063,519	83,543,398	92,467,952	1,131,663,607
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		0	0	0	0	0	0	0
9	LIGHT OIL		196	361	0	21	172	28	37,730
10	COAL		808,541	873,053	825,767	807,051	791,337	897,613	8,784,950
11	GAS		2,540,644	2,529,434	2,415,615	2,132,789	1,703,849	1,869,190	24,915,809
12	NUCLEAR		0	0	0	0	0	0	0
13	SOLAR		1,523	1,370	1,466	1,581	1,322	1,320	8,783
14	OTHER		0	0	0	0	0	0	0
15	TOTAL	MWH	3,350,905	3,404,217	3,242,848	2,941,442	2,496,679	2,768,150	33,747,272
	UNITS OF FUEL BURNED								
16	HEAVY OIL	BBL	0	0	0	0	0	0	0
17	LIGHT OIL	BBL	2,659	2,171	1,600	1,547	763	1,296	92,642
18	COAL	TON	374,952	404,394	383,338	371,774	357,974	402,566	4,125,705
19	GAS	MCF	19,611,346	19,479,289	18,495,895	16,494,189	12,520,654	13,791,646	195,915,062
20	NUCLEAR	MMBTU	0	0	0	0	0	0	0
21	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
22	HEAVY OIL		0	0	0	0	0	0	0
23	LIGHT OIL		15,491	12,636	9,323	9,001	4,442	7,551	534,331
24	COAL		8,667,928	9,317,118	8,810,084	8,481,239	8,154,653	9,154,349	93,826,406
25	GAS		19,611,346	19,479,289	18,495,895	16,494,189	12,520,654	13,791,646	197,955,707
26	NUCLEAR		0	0	0	0	0	0	0
27	OTHER		0	0	0	0	0	0	0
28	TOTAL	MMBTU	28,294,765	28,809,043	27,315,302	24,984,429	20,679,749	22,953,546	292,316,445
	GENERATION MIX (% MWH)								
29	HEAVY OIL		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
30	LIGHT OIL		0.01%	0.01%	0.00%	0.00%	0.01%	0.00%	0.11%
31	COAL		24.13%	25.65%	25.46%	27.44%	31.70%	32.43%	26.03%
32	GAS		75.82%	74.30%	74.49%	72.51%	68.25%	67.53%	73.83%
33	NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	SOLAR		0.05%	0.04%	0.05%	0.05%	0.05%	0.05%	0.03%
35	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
36	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
37	HEAVY OIL	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
38	LIGHT OIL	$/BBL	124.27	140.70	172.45	186.62	316.14	211.25	119.95
39	COAL	$/TON	73.99	74.03	73.88	71.08	71.21	70.92	76.21
40	GAS	$/MCF	3.92	3.96	4.10	4.33	4.62	4.61	4.11
41	NUCLEAR	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
43	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	LIGHT OIL		21.33	24.17	29.60	32.07	54.30	36.26	20.80
45	COAL		3.20	3.21	3.21	3.12	3.13	3.12	3.35
46	GAS		3.92	3.96	4.10	4.33	4.62	4.62	4.07
47	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
48	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
49	TOTAL	$/MMBTU	3.71	3.73	3.82	3.93	4.04	4.03	3.87
	BTU BURNED PER KWH (BTU/KWH)								
50	HEAVY OIL		0	0	0	0	0	0	0
51	LIGHT OIL		78,995	35,003	0	428,619	25,856	274,582	14,162
52	COAL		10,720	10,672	10,669	10,509	10,305	10,199	10,680
53	GAS		7,719	7,701	7,657	7,734	7,348	7,378	7,945
54	NUCLEAR		0	0	0	0	0	0	0
55	OTHER		0	0	0	0	0	0	0
56	TOTAL	BTU/KWH	8,444	8,463	8,423	8,494	8,283	8,292	8,662
	GENERATED FUEL COST PER KWH (C/KWH)								
57	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	LIGHT OIL		168.51	84.61	0.00	1374.74	140.40	995.59	29.45
59	COAL		3.43	3.43	3.43	3.27	3.22	3.18	3.58
60	GAS		3.03	3.05	3.14	3.35	3.39	3.40	3.24
61	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
62	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
63	TOTAL	C/KWH	3.13	3.15	3.22	3.33	3.35	3.34	3.35

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Jul-16

(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	1	376	1,896	0.7	93 23	45.8	10,806	COAL	839 TONS	24.42	20,489	99,960	5 27
2 CRYSTAL RIVER	2	500	115,334	31.0	95 81	32.4	11,250	COAL	53,153 TONS	24.41	1,297,457	4,811,973	4.17
3 CRYSTAL RIVER	4	732	354,521	65.1	91 61	71.0	10,593	COAL	163,995 TONS	22.90	3,755,478	11,660,851	3 29
4 CRYSTAL RIVER	5	712	336,790	63.6	93 23	69.7	10,673	COAL	156,965 TONS	22.90	3,594,504	11,171,491	3 32
5 ANCLOTE	1	517	137,068	35.6	93 87	78.7	10,641	GAS	1,458,508 MCF	1 00	1,458,508	5,885,567	4 29
6 ANCLOTE	2	521	172,599	44.5	94 52	47.1	10,589	GAS	1,827,734 MCF	1 00	1,827,734	6,996,938	4 05
7 AVON PARK	1-2	69	0	0.0	0 00	0.0	0	GAS	0 MCF		0	0	0 00
8 BARTOW	1-4	228	313	0.2	81 29	19.6	13,888	GAS	4,347 MCF	1.00	4,347	17,041	5.44
9 BARTOW CC	1	1279	765,811	80.5	96.77	83.2	7,229	GAS	5,535,696 MCF	1.00	5,535,696	21,700,665	2 83
10 CITRUS CC	1-2	--	0	0.0	0 00	0.0	0	GAS	0 MCF		0	0	0 00
11 DEBARY	1-10	785	2,120	0.4	96.13	10.7	12,784	GAS	27,099 MCF	1.00	27,099	106,231	5 01
12 HIGGINS	1-4	129	187	0.2	91 86	20.7	15,823	GAS	2,962 MCF	1.00	2,962	11,615	6 20
13 HINES CC	1-4	2,204	1,349,593	82.3	94 68	22.0	7,116	GAS	9,603,467 MCF	1 00	9,603,467	37,646,865	2.79
14 INT CITY	1-14	1,186	20,218	2.3	96 22	6.8	12,769	GAS	258,161 MCF	1 00	258,161	1,012,034	5 01
15 OSPREY CC	1	--	0	0.0	0 00	0.0	0	GAS	0 MCF		0	0	0 00
16 SUWANNEE STEAM	1	67	0	0.0	0 00	0.0	0	GAS	0 MCF		0	42,181	0 00
17 SUWANNEE STEAM	2	66	0	0.0	0 00	0.0	0	GAS	0 MCF		0	42,181	0 00
18 SUWANNEE STEAM	3	67	9,987	20.0	94.19	66.8	13,922	GAS	139,039 MCF	1 00	139,039	460,687	4 61
19 SUWANNEE CT	1-3	200	655	0.5	99 03	26.8	13,071	GAS	8,564 MCF	1 00	8,564	33,576	5.12
20 TIGER BAY CC	1	225	48,531	29.0	92 90	82.3	8,850	GAS	429,498 MCF	1 00	429,498	1,683,689	3.47
21 UNIV OF FLA. CC	1	47	33,562	96.0	98 06	97.8	9,424	GAS	316,271 MCF	1 00	316,271	1,239,826	3 69
22 AVON PARK	1-2	69	0	0.0	0 00	0.0	0	LIGHT OIL	0 BBLS		0	0	0 00
23 BARTOW	1-4	228	0	0.0	81 29	0.0	0	LIGHT OIL	0 BBLS		0	1,078	0 00
24 BAYBORO	1-4	231	0	0.0	94.76	0.0	0	LIGHT OIL	0 BBLS		0	936	0 00
25 DEBARY	1-10	785	145	0.4	96.13	96.2	14,411	LIGHT OIL	359 BBLS	5 82	2,091	39,227	27 03
26 HIGGINS	1-4	129	0	0.0	91 86	0.0	0	LIGHT OIL	0 BBLS		0	0	0 00
27 OTHER		0	0	0.0	94 68	0 0	0	LIGHT OIL	0 BBLS		0	0	0 00
28 INT CITY	1-14	1,186	10	2 3	96 22	0 0	15,294	LIGHT OIL	26 BBLS	6 00	156	6,823	66 89
29 RIO PINAR	1	16	0	0 0	0 00	0 0	0	LIGHT OIL	0 BBLS		0	0	0.00
30 SUWANNEE	1-3	200	41	0.5	99 03	0.0	12,770	LIGHT OIL	89 BBLS	5 85	521	7,726	18 94
31 TURNER	1-4	199	0	0.0	0 00	0.0	0	LIGHT OIL	0 BBLS		0	0	0 00
32 OTHER & START UP		-	0	-	0 00	0.0	0	LIGHT OIL	2,185 BBLS	5.82	12,723	274,656	0 00
33 SOLAR		10	1,523	20.5	0 00	0.0	0	SOLAR	0 N/A		0	0	0 00
34 TOTAL			3,350,905								28,294,765	104,953,817	3.13

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Aug-16

(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	1	376	3,442	1.2	86.77	45.8	10,795	COAL	1,541 TONS	24.11	37,158	163,696	4.76
2 CRYSTAL RIVER	2	500	121,736	32.7	98.39	33.3	11,212	COAL	56,610 TONS	24.11	1,364,855	5,142,563	4 22
3 CRYSTAL RIVER	4	732	368,846	67.7	92.26	73.5	10,554	COAL	170,293 TONS	22.86	3,892,893	12,117,522	3 29
4 CRYSTAL RIVER	5	712	379,029	71.6	98.06	73.1	10,612	COAL	175,950 TONS	22.86	4,022,212	12,511,944	3 30
5 ANCLOTE	1	517	162,852	42.3	87.10	48.6	10,265	GAS	1,671,616 MCF	1.00	1,671,616	6,505,575	3 99
6 ANCLOTE	2	521	131,205	33.8	92.90	75.0	10,892	GAS	1,429,152 MCF	1.00	1,429,152	5,768,244	4.40
7 AVON PARK	1-2	69	0	0.0	0.00	0.0	0	GAS	0 MCF		0	0	0 00
8 BARTOW	1-4	228	516	0.3	80.72	19.5	13,905	GAS	7,178 MCF	1.00	7,178	28,412	5 50
9 BARTOW CC	1	1279	756,724	79.5	95.16	83.4	7,229	GAS	5,470,586 MCF	1.00	5,470,586	21,654,309	2 86
10 CITRUS CC	1-2	--	0	0.0	0.00	0.0	0	GAS	0 MCF		0	0	0 00
11 DEBARY	1-10	785	3,272	0.6	96.10	11.2	12,794	GAS	41,858 MCF	1.00	41,858	165,687	5 06
12 HIGGINS	1-4	129	295	0.3	91.78	20.8	15,747	GAS	4,647 MCF	1.00	4,647	18,391	6 23
13 HINES CC	1-4	2,204	1,353,551	82.5	94.52	22.1	7,110	GAS	9,623,241 MCF	1.00	9,623,241	38,091,834	2 81
14 INT CITY	1-14	1,186	23,338	2.7	96.36	6.8	12,765	GAS	297,911 MCF	1.00	297,911	1,179,223	5 05
15 OSPREY CC	1	--	0	0.0	0.00	0.0	0	GAS	0 MCF		0	0	0 00
16 SUWANNEE STEAM	1	67	0	0.0	0.00	0.0	0	GAS	0 MCF		0	42,870	0 00
17 SUWANNEE STEAM	2	66	0	0.0	0.00	0.0	0	GAS	0 MCF		0	42,870	0 00
18 SUWANNEE STEAM	3	67	10,125	20.3	95.81	67.8	13,848	GAS	140,204 MCF	1.00	140,204	469,230	4 63
19 SUWANNEE CT	1-3	200	1,253	0.9	99.25	25.7	13,071	GAS	16,380 MCF	1.00	16,380	64,838	5.17
20 TIGER BAY CC	1	225	53,293	31.8	92.90	83.1	8,732	GAS	465,369 MCF	1.00	465,369	1,842,079	3.46
21 UNIV OF FLA. CC	1	47	33,010	94.4	96.45	97.8	9,426	GAS	311,147 MCF	1.00	311,147	1,231,619	3.73
22 AVON PARK	1-2	69	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS		0	0	0 00
23 BARTOW	1-4	228	17	0.3	80.72	0.0	13,721	LIGHT OIL	40 BBLS	5.90	236	3,147	18 30
24 BAYBORO	1-4	231	25	0.0	95.57	10.9	13,294	LIGHT OIL	58 BBLS	5.78	335	3,878	15 39
25 DEBARY	1-10	785	233	0.6	96.10	0.0	13,217	LIGHT OIL	529 BBLS	5.82	3,077	47,990	20 61
26 HIGGINS	1-4	129	0	0.0	91.78	0.0	0	LIGHT OIL	0 BBLS		0	0	0 00
27 OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS		0	0	0 00
28 INT CITY	1-14	1,186	55	2.7	96.36	0.0	14,511	LIGHT OIL	138 BBLS	5.80	801	12,452	22 56
29 RIO PINAR	1	16	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS		0	0	0 00
30 SUWANNEE	1-3	200	31	0.9	99.25	0.0	12,516	LIGHT OIL	66 BBLS	5.80	383	6,461	21.11
31 TURNER	1-4	199	0	0.0	0.00	0.0	0	LIGHT OIL	0 BBLS		0	0	0 00
32 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,340 BBLS	5.82	7,804	231,525	0 00
33 SOLAR		10	1,370	18.4	0.00	0.0	0	SOLAR	0 N/A		0	0	0 00
34 TOTAL			3,404,217								28,809,043	107,346,359	3.15

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Sep-16

(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	1	376	0	0.0	91.33	0.0	0	COAL	0	TONS		0	24,355	0.00
2 CRYSTAL RIVER	2	500	109,581	30.4	97.00	32.5	11,243	COAL	51,548	TONS	23.90	1,232,008	4,693,666	4.28
3 CRYSTAL RIVER	4	732	368,526	69.9	95.00	73.6	10,550	COAL	170,226	TONS	22.84	3,887,963	12,102,484	3.28
4 CRYSTAL RIVER	5	712	347,660	67.8	94.00	72.9	10,614	COAL	161,564	TONS	22.84	3,690,113	11,499,041	3.31
5 ANCLOTE	1	517	157,870	42.4	89.00	47.6	10,279	GAS	1,622,699	MCF	1.00	1,622,699	6,534,643	4.14
6 ANCLOTE	2	521	125,861	33.6	96.00	71.7	10,943	GAS	1,377,299	MCF	1.00	1,377,299	5,763,841	4.58
7 AVON PARK	1-2	69	0	0.0	0.00	0.0	0	GAS	0	MCF		0	0	0.00
8 BARTOW	1-4	228	50	0.0	81.67	22.0	13,944	GAS	700	MCF	1.00	700	2,867	5.71
9 BARTOW CC	1	1279	737,493	80.1	95.67	83.7	7,230	GAS	5,332,391	MCF	1.00	5,332,391	21,860,115	2.96
10 CITRUS CC	1-2	--	0	0.0	0.00	0.0	0	GAS	0	MCF		0	0	0.00
11 DEBARY	1-10	785	751	0.1	96.37	12 0	12,801	GAS	9,607	MCF	1.00	9,607	39,383	5.25
12 HIGGINS	1-4	129	0	0 0	91.67	0 0	0	GAS	0	MCF		0	0	0.00
13 HINES CC	1-4	2,204	1,306,969	82.4	94.33	22.1	7,108	GAS	9,289,635	MCF	1.00	9,289,635	38,082,822	2.91
14 NT CITY	1-14	1,186	11,756	1.4	96.63	6.8	12,788	GAS	150,330	MCF	1.00	150,330	616,274	5.24
15 OSPREY CC	1	--	0	0.0	0.00	0.0	0	GAS	0	MCF		0	0	0.00
16 SUWANNEE STEAM	1	67	0	0.0	0.00	0.0	0	GAS	0	MCF		0	37,118	0.00
17 SUWANNEE STEAM	2	66	0	0.0	0.00	0.0	0	GAS	0	MCF		0	37,118	0.00
18 SUWANNEE STEAM	3	67	8,300	17.2	91.33	65.5	13,997	GAS	116,176	MCF	1.00	116,176	402,027	4.84
19 SUWANNEE CT	1-3	200	172	0.1	99.45	28.6	13,083	GAS	2,245	MCF	1.00	2,245	9,199	5.36
20 TIGER BAY CC	1	225	48,398	29.9	92.00	82.7	8,781	GAS	424,999	MCF	1.00	424,999	1,742,283	3.60
21 UNIV OF FLA. CC	1	47	17,995	53.2	95.88	97 9	9,437	GAS	169,814	MCF	1.00	169,814	696,151	3.87
22 AVON PARK	1-2	69	0	0.0	0.00	0 0	0	LIGHT OIL	0	BBLS		0	0	0.00
23 BARTOW	1-4	228	0	0.0	81.67	0.0	0	LIGHT OIL	0	BBLS		0	1,078	0.00
24 BAYBORO	1-4	231	0	0.0	96.17	0.0	0	LIGHT OIL	0	BBLS		0	936	0.00
25 DEBARY	1-10	785	0	0.0	96.37	0.0	0	LIGHT OIL	0	BBLS		0	20,664	0.00
26 HIGGINS	1-4	129	0	0.0	91.67	0 0	0	LIGHT OIL	0	BBLS		0	0	0.00
27 OTHER		0	0	0.0	0.00	0 0	0	LIGHT OIL	0	BBLS		0	0	0.00
28 NT CITY	1-14	1,186	0	0 0	96.63	0 0	0	LIGHT OIL	0	BBLS		0	5,467	0.00
29 RIO PINAR	1	16	0	0.0	0.00	0 0	0	LIGHT OIL	0	BBLS		0	0	0.00
30 SUWANNEE	1-3	200	0	0 0	99.45	0 0	0	LIGHT OIL	0	BBLS		0	2,951	0.00
31 TURNER	1-4	199	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
32 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,600	BBLS	5.83	9,323	244,830	0.00
33 SOLAR		10	1,466	20.4	0.00	0.0	0	SOLAR	0	N/A		0	0	0.00
34 TOTAL			3,242,848									27,315,302	104,419,313	3.22

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Oct-16

(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	1	376	1,085	0.4	91.61	41.2	10,818	COAL	493 TONS	23 81	11,738	68,960	6.36
2 CRYSTAL RIVER	2	500	1,275	0.3	98.06	36.4	11,027	COAL	591 TONS	23.79	14,059	77,780	6.10
3 CRYSTAL RIVER	4	732	415,713	76.3	96.77	78.9	10,476	COAL	190,928 TONS	22 81	4,355,071	13,527,163	3.25
4 CRYSTAL RIVER	5	712	388,978	73.4	95.16	77.8	10,541	COAL	179,762 TONS	22 81	4,100,371	12,750,330	3.28
5 ANCLOTE	1	517	150,004	39.0	87.10	44.8	10,337	GAS	1,550,549 MCF	1 00	1,550,549	6,514,585	4.34
6 ANCLOTE	2	521	105,682	27.3	94.19	67.6	11,004	GAS	1,162,973 MCF	1 00	1,162,973	5,223,571	4.94
7 AVON PARK	1-2	69	0	0.0	0.00	0.0	0	GAS	0 MCF		0	0	0.00
8 BARTOW	1-4	228	143	0.1	82.90	21.0	13,954	GAS	2,001 MCF	1 00	2,001	8,658	6.04
9 BARTOW CC	1	1279	792,476	83.3	98.71	84.3	7,217	GAS	5,718,933 MCF	1 00	5,718,933	24,738,968	3.12
10 CITRUS CC	1-2	--	0	0.0	0.00	0.0	0	GAS	0 MCF		0	0	0.00
11 DEBARY	1-10	785	1,056	0.2	96.81	10.3	12,831	GAS	13,544 MCF	1 00	13,544	58,592	5.55
12 HIGGINS	1-4	129	66	0.1	92.18	25.7	16,193	GAS	1,072 MCF	1 00	1,072	4,639	7.01
13 HINES CC	1-4	2,204	985,143	60.1	94.52	21.9	7,197	GAS	7,090,171 MCF	1 00	7,090,171	30,670,674	3.11
14 NT CITY	1-14	1,186	11,858	1.3	95.02	6.8	12,813	GAS	151,938 MCF	1 00	151,938	657,249	5.54
15 OSPREY CC	1	--	0	0.0	0.00	0.0	0	GAS	0 MCF		0	0	0.00
16 SUWANNEE STEAM	1	67	0	0.0	0.00	0.0	0	GAS	0 MCF		0	32,378	0.00
17 SUWANNEE STEAM	2	66	0	0.0	0.00	0.0	0	GAS	0 MCF		0	32,378	0.00
18 SUWANNEE STEAM	3	67	6,939	13.9	91.29	63.5	14,072	GAS	97,641 MCF	1 00	97,641	357,621	5.15
19 SUWANNEE CT	1-3	200	395	0.3	99.14	25.3	13,082	GAS	5,170 MCF	1 00	5,170	22,364	5.66
20 TIGER BAY CC	1	225	45,245	27.0	92.90	84.5	8,440	GAS	381,864 MCF	1 00	381,864	1,651,870	3.65
21 UNIV OF FLA. CC	1	47	33,782	96.6	98.71	97.9	9,423	GAS	318,333 MCF	1 00	318,333	1,377,044	4.08
22 AVON PARK	1-2	69	0	0.0	0.00	0.0	0	LIGHT O L	0 BBLS		0	0	0.00
23 BARTOW	1-4	228	0	0.0	82.90	0.0	0	LIGHT O L	0 BBLS		0	1,078	0.00
24 BAYBORO	1-4	231	0	0.0	96.61	0.0	0	LIGHT O L	0 BBLS		0	936	0.00
25 DEBARY	1-10	785	0	0.0	96.81	0.0	0	LIGHT O L	0 BBLS		0	20,664	0.00
26 HIGGINS	1-4	129	0	0.0	92.18	0.0	0	LIGHT O L	0 BBLS		0	0	0.00
27 OTHER		0	0	0.0	0.00	0.0	0	LIGHT O L	0 BBLS		0	0	0.00
28 NT CITY	1-14	1,186	12	1.3	95.02	0.0	15,833	LIGHT O L	33 BBLS	5.76	190	7,453	62.11
29 RIO PINAR	1	16	0	0.0	0.00	0.0	0	LIGHT O L	0 BBLS		0	0	0.00
30 SUWANNEE	1-3	200	9	0.3	99.14	0.0	16,889	LIGHT O L	26 BBLS	5 85	152	4,604	51.16
31 TURNER	1-4	199	0	0.0	0.00	0.0	0	LIGHT O L	0 BBLS		0	0	0.00
32 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT O L	1,488 BBLS	5 82	8,659	253,960	0.00
33 SOLAR		10	1,581	21.3	0.00	0.0	0	SOLAR	0 N/A		0	0	0.00
34 TOTAL			2,941,442								24,984,429	98,063,519	3.33

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Nov-16

	(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	1	376	0	0.0	94.00	0.0	0	COAL	0	TONS		0	24,355	0.00
2	CRYSTAL RIVER	2	500	0	0.0	96.00	0.0	0	COAL	0	TONS		0	24,355	0.00
3	CRYSTAL RIVER	4	732	385,589	73.2	99.67	73.4	10,372	COAL	175,566	TONS	22.78	3,999,396	12,482,350	3.24
4	CRYSTAL RIVER	5	712	405,748	79.1	98.00	80.9	10,241	COAL	182,408	TONS	22.78	4,155,257	12,959,285	3.19
5	ANCLOTE	1	517	61,615	16.6	88.67	37.4	10,305	GAS	634,973	MCF	1.00	634,973	2,613,868	4.24
6	ANCLOTE	2	521	10,115	2.7	97.50	60.7	10,910	GAS	110,352	MCF	1.00	110,352	827,535	8.18
7	AVON PARK	1-2	69	0	0.0	0.00	0.0	0	GAS	0	MCF		0	0	0.00
8	BARTOW	1-4	228	0	0.0	81.84	0.0	0	GAS	0	MCF		0	0	0.00
9	BARTOW CC	1	1279	803,561	87.3	97.33	89.6	7,070	GAS	5,681,354	MCF	1.00	5,681,354	26,232,619	3.26
10	CITRUS CC	1-2	--	0	0.0	0.00	0.0	0	GAS	0	MCF		0	0	0.00
11	DEBARY	1-10	785	208	0.1	96.80	0.0	12,367	GAS	2,571	MCF	1.00	2,571	11,871	5.71
12	HIGG NS	1-4	129	0	0.0	92.09	0.0	0	GAS	0	MCF		0	0	0.00
13	H NES CC	1-4	2,204	754,628	47.6	94.75	19.4	7,157	GAS	5,401,069	MCF	1.00	5,401,069	24,938,450	3.30
14	INT CITY	1-14	1,186	6,363	0.7	95.62	7.0	12,655	GAS	80,531	MCF	1.00	80,531	371,835	5.84
15	OSPREY CC	1	--	0	0.0	0.00	0.0	0	GAS	0	MCF		0	0	0.00
16	SUWANNEE STEAM	1	67	0	0.0	0.00	0.0	0	GAS	0	MCF		0	0	0.00
17	SUWANNEE STEAM	2	66	0	0.0	0.00	0.0	0	GAS	0	MCF		0	0	0.00
18	SUWANNEE STEAM	3	67	0	0.0	0.00	0 0	0	GAS	0	MCF		0	0	0.00
19	SUWANNEE CT	1-3	200	114	0.1	99.34	28 5	12,195	GAS	1,389	MCF	1.00	1,389	6,417	5.63
20	TIGER BAY CC	1	225	33,375	20.6	94.33	93 3	8,664	GAS	289,159	MCF	1.00	289,159	1,335,138	4.00
21	UNIV OF FLA. CC	1	47	33,869	100.1	98.00	102.1	9,426	GAS	319,256	MCF	1.00	319,256	1,474,105	4.35
22	AVON PARK	1-2	69	0	0.0	0.00	0 0	0	LIGHT OIL	0	BBLS		0	0	0.00
23	BARTOW	1-4	228	3	0.0	81.84	0.0	22,000	LIGHT OIL	11	BBLS	6.00	66	1,770	59.00
24	BAYBORO	1-4	231	0	0.0	96.25	0.0	0	LIGHT OIL	0	BBLS		0	936	0.00
25	DEBARY	1-10	785	136	0.1	96.80	4.3	13,631	LIGHT OIL	318	BBLS	5.81	1,847	40,353	29.78
26	HIGG NS	1-4	129	0	0.0	92.09	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
27	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
28	INT CITY	1-14	1,186	33	0.7	95.62	0.0	14,685	LIGHT OIL	84	BBLS	5.82	489	10,605	31.85
29	RIO P NAR	1	16	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
30	SUWANNEE	1-3	200	0	0.0	99.34	0.0	0	LIGHT OIL	0	BBLS		0	2,951	0.00
31	TURNER	1-4	199	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
32	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	350	BBLS	5.83	2,040	184,600	0.00
33	SOLAR		10	1,322	18.4	0.00	0.0	0	SOLAR	0	N/A		0	0	0.00
34	TOTAL			2,496,679									20,679,749	83,543,398	3.35

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Dec-16

(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	1	376	0	0.0	93.23	0.0	0	COAL	0	TONS		0	24,355	0.00
2 CRYSTAL RIVER	2	500	0	0.0	94.52	0.0	0	COAL	0	TONS		0	24,355	0.00
3 CRYSTAL RIVER	4	732	428,608	78.7	93.55	84.1	10,260	COAL	193,376	TONS	22.74	4,397,374	13,700,161	3.20
4 CRYSTAL RIVER	5	712	469,005	88.5	97.10	91.2	10,143	COAL	209,190	TONS	22.74	4,756,975	14,800,542	3.16
5 ANCLOTE	1	517	106,874	27.8	93.23	29.8	10,426	GAS	1,114,234	MCF	1.00	1,114,234	4,605,426	4.31
6 ANCLOTE	2	521	19,541	5.0	92.14	38.7	11,482	GAS	224,376	MCF	1.00	224,376	1,571,899	8.04
7 AVON PARK	1-2	69	0	0.0	0.00	0.0	0	GAS	0	MCF		0	0	0.00
8 BARTOW	1-4	228	12	0.0	82.82	0.0	13,115	GAS	160	MCF	1.00	160	740	6.07
9 BARTOW CC	1	1279	750,653	78.9	94.84	83.1	7,123	GAS	5,346,637	MCF	1.00	5,346,637	24,673,297	3.29
10 CITRUS CC	1-2	--	0	0.0	0.00	0.0	0	GAS	0	MCF		0	0	0.00
11 DEBARY	1-10	785	137	0.0	96.68	9.6	12,591	GAS	1,730	MCF	1.00	1,730	7,984	5.81
12 HIGGINS	1-4	129	0	0.0	92.18	0.0	0	GAS	0	MCF		0	0	0.00
13 HINES CC	1-4	2,204	947,172	57.8	93.87	22.4	7,053	GAS	6,680,543	MCF	1.00	6,680,543	30,828,916	3.25
14 NT CITY	1-14	1,186	2,481	0.3	95.18	7.8	12,420	GAS	30,807	MCF	1.00	30,807	142,166	5.73
15 OSPREY CC	1	--	0	0.0	0.00	0.0	0	GAS	0	MCF		0	0	0.00
16 SUWANNEE STEAM	1	67	0	0.0	0.00	0.0	0	GAS	0	MCF		0	0	0.00
17 SUWANNEE STEAM	2	66	0	0.0	0.00	0.0	0	GAS	0	MCF		0	0	0.00
18 SUWANNEE STEAM	3	67	0	0.0	0.00	0.0	0	GAS	0	MCF		0	0	0.00
19 SUWANNEE CT	1-3	200	20	0.0	98.60	0.0	12,637	GAS	254	MCF	1.00	254	1,172	5.83
20 TIGER BAY CC	1	225	7,163	4.3	92.58	93.6	8,620	GAS	61,746	MCF	1.00	61,746	284,943	3.98
21 UNIV OF FLA. CC	1	47	35,136	100.5	98.39	102.1	9,425	GAS	331,159	MCF	1.00	331,159	1,528,210	4.35
22 AVON PARK	1-2	69	0	0.0	0.00	0.0	0	LIGHT O L	0	BBLS		0	0	0.00
23 BARTOW	1-4	228	5	0.0	82.82	0.0	17,347	LIGHT O L	15	BBLS	5.67	85	1,969	40.18
24 BAYBORO	1-4	231	0	0.0	95.89	0.0	0	LIGHT O L	0	BBLS		0	936	0.00
25 DEBARY	1-10	785	14	0.0	96.68	0.0	15,147	LIGHT O L	35	BBLS	5.89	206	22,858	168.07
26 HIGGINS	1-4	129	0	0.0	92.18	0.0	0	LIGHT O L	0	BBLS		0	0	0.00
27 OTHER		0	0	0.0	0.00	0.0	0	LIGHT O L	0	BBLS		0	0	0.00
28 NT CITY	1-14	1,186	9	0.3	95.18	0.0	14,444	LIGHT O L	22	BBLS	5.91	130	6,827	75.86
29 RIO PINAR	1	16	0	0.0	0.00	0.0	0	LIGHT O L	0	BBLS		0	0	0.00
30 SUWANNEE	1-3	200	0	0.0	98.60	0.0	0	LIGHT O L	0	BBLS		0	2,951	0.00
31 TURNER	1-4	199	0	0.0	0.00	0.0	0	LIGHT O L	0	BBLS		0	0	0.00
32 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT O L	1,224	BBLS	5.83	7,130	238,245	0.00
33 SOLAR		10	1,320	17.7	0.00	0.0	0	SOLAR	0	N/A		0	0	0.00
34 TOTAL			2,768,150									22,953,546	92,467,952	3.34

Duke Energy Florida
Inventory Analysis
Estimated for the Period of : January through December 2016

			Act Jan-16	Act Feb-16	Act Mar-16	Act Apr-16	Act May-16	Act Jun-16	Subtotal
	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	
11	UNIT COST	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	
12	AMOUNT	$	(2,206)	(2,206)	(2,206)	(2,206)	(2,206)	(2,206)	
	LIGHT OIL								
13	PURCHASES:								
14	UNITS	BBL	(1)	(1)	(178)	27,678	37,332	30,177	95,007
15	UNIT COST	$/BBL	(138,074.13)	(285,546.35)	(589.99)	69.73	63.15	76.43	74.97
16	AMOUNT	$	138,074	285,546	105,017	1,930,068	2,357,603	2,306,544	7,122,854
17	BURNED:								
18	UNITS	BBL	8,322	4,612	12,546	7,501	12,418	37,207	82,606
19	UNIT COST	$/BBL	132.91	133.09	124.63	120.83	112.08	102.53	113.75
20	AMOUNT	$	1,106,067	613,795	1,563,581	906,310	1,391,758	3,814,995	9,396,506
21	ENDING INVENTORY:								
22	UNITS	BBL	947,635	943,024	930,299	950,476	975,390	967,878	
23	UNIT COST	$/BBL	113.60	113.81	113.80	112.46	110.58	109.83	
24	AMOUNT	$	107,651,683	107,323,435	105,864,871	106,888,629	107,854,475	106,298,921	
	COAL								
25	PURCHASES:								
26	UNITS	TON	214,217	235,506	180,293	260,133	238,017	351,077	1,479,243
27	UNIT COST	$/TON	80.22	76.95	82.12	72.94	86.85	80.80	79.85
28	AMOUNT	$	17,185,485	18,121,443	14,806,060	18,973,048	20,672,017	28,366,760	118,124,813
29	BURNED:								
30	UNITS	TON	296,581	229,237	189,735	321,898	323,704	469,552	1,830,707
31	UNIT COST	$/TON	81.12	79.44	81.79	78.33	81.91	81.89	80.83
32	AMOUNT	$	24,059,366	18,210,138	15,519,123	25,215,560	26,515,970	38,453,893	147,974,050
33	ENDING INVENTORY:								
34	UNITS	TON	882,732	889,001	879,559	817,794	732,106	613,631	
35	UNIT COST	$/TON	83.06	82.38	82.45	81.04	82.55	82.05	
36	AMOUNT	$	73,320,730	73,232,036	72,518,972	66,276,461	60,432,508	50,345,374	
	GAS								
37	BURNED:								
38	UNITS	MCF	16,262,865	14,951,085	15,536,706	14,358,141	16,750,343	17,662,903	95,522,043
39	UNIT COST	$/MCF	4.29	4.32	3.94	3.95	3.75	3.86	4.01
40	AMOUNT	$	69,816,371	64,589,789	61,263,135	56,695,852	62,894,953	68,238,594	383,498,693
	NUCLEAR								
41	BURNED:								
42	UNITS	MMBTU	0	0	0	0	0	0	0
43	UNIT COST	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	AMOUNT	$	0	0	0	0	0	0	0

Duke Energy Florida
Inventory Analysis
Estimated for the Period of : January through December 2016

			Est Jul-16	Est Aug-16	Est Sep-16	Est Oct-16	Est Nov-16	Est Dec-16	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	
11	UNIT COST	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	
12	AMOUNT	$	0	0	0	0	0	0	
	LIGHT OIL								
13	PURCHASES:								
14	UNITS	BBL	2,659	2,171	1,600	1,547	763	1,296	105,043
15	UNIT COST	$/BBL	124.27	140.70	172.45	186.62	316.14	211.25	84.14
16	AMOUNT	$	330,446	305,453	275,926	288,695	241,215	273,786	8,838,375
17	BURNED:								
18	UNITS	BBL	2,659	2,171	1,600	1,547	763	1,296	92,642
19	UNIT COST	$/BBL	124.27	140.70	172.45	186.62	316.14	211.25	119.95
20	AMOUNT	$	330,446	305,453	275,926	288,695	241,215	273,786	11,112,027
21	ENDING INVENTORY:								
22	UNITS	BBL	967,878	967,878	967,878	967,878	967,878	967,878	
23	UNIT COST	$/BBL	109.83	109.83	109.83	109.83	109.83	109.83	
24	AMOUNT	$	106,298,921	106,298,921	106,298,921	106,298,921	106,298,921	106,298,921	
	COAL								
25	PURCHASES:								
26	UNITS	TON	374,952	404,394	383,338	371,774	357,974	402,566	3,774,241
27	UNIT COST	$/TON	73.99	74.03	73.88	71.08	71.21	70.92	75.40
28	AMOUNT	$	27,744,275	29,935,725	28,319,546	26,424,233	25,490,345	28,549,413	284,588,350
29	BURNED:								
30	UNITS	TON	374,952	404,394	383,338	371,774	357,974	402,566	4,125,705
31	UNIT COST	$/TON	73.99	74.03	73.88	71.08	71.21	70.92	76.21
32	AMOUNT	$	27,744,275	29,935,725	28,319,546	26,424,233	25,490,345	28,549,413	314,437,587
33	ENDING INVENTORY:								
34	UNITS	TON	613,631	613,631	613,631	613,631	613,631	613,631	
35	UNIT COST	$/TON	73.99	74.03	73.88	71.08	71.21	70.92	
36	AMOUNT	$	45,405,135	45,424,710	45,332,726	43,614,498	43,695,007	43,517,851	
	GAS								
37	BURNED:								
38	UNITS	MCF	19,611,346	19,479,289	18,495,895	16,494,189	12,520,654	13,791,646	195,915,062
39	UNIT COST	$/MCF	3.92	3.96	4.10	4.33	4.62	4.61	4.11
40	AMOUNT	$	76,879,096	77,105,181	75,823,841	71,350,591	57,811,838	63,644,753	806,113,993
	NUCLEAR								
41	BURNED:								
42	UNITS	MMBTU	0	0	0	0	0	0	0
43	UNIT COST	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	AMOUNT	$	0	0	0	0	0	0	0

Duke Energy Florida
Fuel Cost of Power Sold
Estimated for the Period of : January through December 2016

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH		C/KWH				REFUNDABLE
		TYPE	TOTAL	WHEELED	MWH	(A)	(B)	TOTAL $	TOTAL	GAIN ON
MONTH	SOLD TO	&	MWH	FROM	FROM	FUEL	TOTAL	FOR	COST	POWER
		SCHED	SOLD	OTHER	OWN	COST	COST	FUEL ADJ	$	SALES
				SYSTEMS	GENERATION			(6) x (7)(A)	(6) x (7)(B)	$
Jan-16	ECONSALE	--	12,825		12,825	2.403	3.339	308,216	428,281	120,066
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	84,267		84,267	2.686	2.686	2,263,375	2,263,375	0
	TOTAL		97,092		97,092	2.649	2.772	2,571,591	2,691,656	120,066
Feb-16	ECONSALE	--	2,029		2,029	2.155	3.064	43,732	62,170	18,437
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	--	53,295		53,295	2.408	2.408	1,283,444	1,283,444	0
	TOTAL		55,324		55,324	2.399	2.432	1,327,177	1,345,614	18,437
Mar-16	ECONSALE	--	6,579		6,579	3.334	3.088	219,326	203,188	(16,138)
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	--	62,510		62,510	1.953	1.953	1,220,643	1,220,643	0
	TOTAL		69,089		69,089	2.084	2.061	1,439,969	1,423,831	(16,138)
Apr-16	ECONSALE	--	19,501		19,501	2.281	3.099	444,871	604,257	159,385
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	--	71,084		71,084	2.150	2.150	1,528,531	1,528,531	0
	TOTAL		90,585		90,585	2.179	2.354	1,973,402	2,132,787	159,385
May-16	ECONSALE	--	524		524	2.593	(0.726)	13,586	(3,806)	(17,392)
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	--	82,369		82,369	2.306	2.306	1,899,190	1,899,190	0
	TOTAL		82,893		82,893	2.308	2.287	1,912,776	1,895,385	(17,392)
Jun-16	ECONSALE	--	25		25	2.308	2.194	577	549	(29)
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	--	168,079		168,079	2.498	2.498	4,197,841	4,197,841	0
	TOTAL		168,104		168,104	2.498	2.497	4,198,419	4,198,390	(29)
Jan-16	ECONSALE	--	41,483		41,483	2.484	3.121	1,030,308	1,294,638	264,330
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Jun-16	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	521,604		521,604	2.376	2.376	12,393,025	12,393,025	0
	TOTAL		563,087		563,087	2.384	2.431	13,423,333	13,687,664	264,330

Duke Energy Florida
Fuel Cost of Power Sold
Estimated for the Period of : January through December 2016

(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-16	ECONSALE	--	10,552		10,552	2.892	3.595	305,124	379,393	74,269
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	--	136,341		136,341	1.585	1.585	2,161,098	2,161,098	0
	TOTAL		146,893		146,893	1.679	1.729	2,466,222	2,540,491	74,269
Aug-16	ECONSALE	--	9,458		9,458	2.924	3.636	276,610	343,939	67,329
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	--	136,451		136,451	1.642	1.642	2,240,948	2,240,948	0
	TOTAL		145,909		145,909	1.725	1.772	2,517,558	2,584,887	67,329
Sep-16	ECONSALE	--	3,987		3,987	2.785	3.463	111,035	138,062	27,027
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	--	121,368		121,368	1.626	1.626	1,973,483	1,973,483	0
	TOTAL		125,355		125,355	1.663	1.684	2,084,518	2,111,545	27,027
Oct-16	ECONSALE	--	3,672		3,672	2.909	3.616	106,787	132,779	25,992
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	--	151,276		151,276	1.106	1.106	1,672,912	1,672,912	0
	TOTAL		154,948		154,948	1.149	1.165	1,779,699	1,805,691	25,992
Nov-16	ECONSALE	--	13,683		13,683	2.607	3.242	356,771	443,611	86,840
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	--	71,809		71,809	1.502	1.502	1,078,740	1,078,740	0
	TOTAL		85,492		85,492	1.679	1.781	1,435,511	1,522,351	86,840
Dec-16	ECONSALE	--	6,532		6,532	2.482	3.086	162,116	201,576	39,460
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	--	60,171		60,171	2.487	2.487	1,496,660	1,496,660	0
	TOTAL		66,703		66,703	2.487	2.546	1,658,776	1,698,236	39,460
Jan-16	ECONSALE	--	89,367		89,367	2.628	3.283	2,348,751	2,933,998	585,247
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-16	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	1,199,020		1,199,020	1.920	1.920	23,016,866	23,016,866	0
	TOTAL		1,288,387		1,288,387	1.969	2.014	25,365,617	25,950,864	585,247

Duke Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January through December 2016

(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-16	OTHER	--	0			0	0.000	0.000	0
Act	Osprey (Calpine)	--	77,777			77,777	3.377	3.377	2,626,236
	SHADY HILLS	--	3,038			3,038	7.710	7.710	234,234
	SOCO Franklin	--	45,000			45,000	3.335	3.335	1,500,593
	SOCO Scherer	--	0			0	0.000	0.000	278
	Vandolah (NSG)	--	12,381			12,381	4.650	4.650	575,694
	TOTAL		138,196	0	0	138,196	3.572	3.572	4,937,035
Feb-16	OTHER	--	0			0	0.000	0.000	0
Act	Osprey (Calpine)	--	128,181			128,181	3.288	3.288	4,214,844
	SHADY HILLS	--	6			6	-262.759	-262.759	(15,766)
	SOCO Franklin	--	52,600			52,600	2.945	2.945	1,549,265
	SOCO Scherer	--	0			0	0.000	0.000	53,812
	Vandolah (NSG)	--	4,172			4,172	9.948	9.948	415,018
	TOTAL		184,959	0	0	184,959	3.361	3.361	6,217,173
Mar-16	OTHER	--	0			0	0.000	0.000	0
Act	Osprey (Calpine)	--	143,784			143,784	3.014	3.014	4,333,882
	SHADY HILLS	--	80,981			80,981	4.721	4.721	3,823,075
	SOCO Franklin	--	107,600			107,600	2.274	2.274	2,447,103
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	83,365			83,365	4.579	4.579	3,817,678
	TOTAL		415,730	0	0	415,730	3.469	3.469	14,421,739
Apr-16	OTHER	--	0			0	0.000	0.000	0
Act	Osprey (Calpine)	--	40,107			40,107	3.439	3.439	1,379,237
	SHADY HILLS	--	99,020			99,020	4.541	4.541	4,496,432
	SOCO Franklin	--	158,163			158,163	2.158	2.158	3,413,844
	SOCO Scherer	--	3,081			3,081	3.535	3.535	108,910
	Vandolah (NSG)	--	254,214			254,214	4.203	4.203	10,685,810
	TOTAL		554,585	0	0	554,585	3.621	3.621	20,084,233
May-16	OTHER	--	0			0	0.000	0.000	0
Act	Osprey (Calpine)	--	151,769			151,769	2.902	2.902	4,403,799
	SHADY HILLS	--	270,381			270,381	3.936	3.936	10,641,072
	SOCO Franklin	--	158,500			158,500	2.331	2.331	3,694,039
	SOCO Scherer	--	2,478			2,478	3.717	3.717	92,101
	Vandolah (NSG)	--	355,275			355,275	3.937	3.937	13,987,124
	TOTAL		938,403	0	0	938,403	3.497	3.497	32,818,134
Jun-16	OTHER	--	0			0	0.000	0.000	0
Act	Osprey (Calpine)	--	189,973			189,973	2.932	2.932	5,570,883
	SHADY HILLS	--	202,157			202,157	4.259	4.259	8,610,653
	SOCO Franklin	--	201,536			201,536	2.679	2.679	5,399,700
	SOCO Scherer	--	0			0	0.000	0.000	63
	Vandolah (NSG)	--	282,329			282,329	4.260	4.260	12,027,400
	TOTAL		875,995	0	0	875,995	3.608	3.608	31,608,698
Jan-16	OTHER	--	0			0	0.000	0.000	0
THRU	Osprey (Calpine)	--	731,591			731,591	3.079	3.079	22,528,881
Jun-16	SHADY HILLS	--	655,583			655,583	4.239	4.239	27,789,700
	SOCO Franklin	--	723,399			723,399	2.489	2.489	18,004,544
	SOCO Scherer	--	5,559			5,559	4.590	4.590	255,163
	Vandolah (NSG)	--	991,736			991,736	4.185	4.185	41,508,724
	TOTAL		3,107,868	0	0	3,107,868	3.542	3.542	110,087,011

Duke Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January through December 2016

(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)
Jul-16	OTHER	--	0			0	0.000	0.000	0
Est	Osprey (Calpine)	--	166,088			166,088	3.202	3.202	5,317,440
	SHADY HILLS	--	93,819			93,819	4.306	4.306	4,039,468
	SOCO Franklin	--	205,354			205,354	2.662	2.662	5,467,122
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	108,351			108,351	4.995	4.995	5,411,710
	TOTAL		573,611	0	0	573,611	3.528	3.528	20,235,740
Aug-16	OTHER	--	0			0	0.000	0.000	0
Est	Osprey (Calpine)	--	171,418			171,418	3.224	3.224	5,525,731
	SHADY HILLS	--	80,316			80,316	4.403	4.403	3,536,101
	SOCO Franklin	--	191,920			191,920	2.786	2.786	5,347,777
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	113,592			113,592	4.998	4.998	5,677,011
	TOTAL		557,245	0	0	557,245	3.605	3.605	20,086,620
Sep-16	OTHER	--	0			0	0.000	0.000	0
Est	Osprey (Calpine)	--	165,649			165,649	3.332	3.332	5,520,174
	SHADY HILLS	--	42,021			42,021	4.534	4.534	1,905,389
	SOCO Franklin	--	180,645			180,645	2.846	2.846	5,140,380
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	91,522			91,522	5.242	5.242	4,797,692
	TOTAL		479,837	0	0	479,837	3.619	3.619	17,363,635
Oct-16	OTHER	--	0			0	0.000	0.000	0
Est	Osprey (Calpine)	--	39,261			39,261	3.499	3.499	1,373,709
	SHADY HILLS	--	37,233			37,233	4.812	4.812	1,791,743
	SOCO Franklin	--	165,185			165,185	2.932	2.932	4,843,890
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	65,195			65,195	5.521	5.521	3,599,447
	TOTAL		306,874	0	0	306,874	3.783	3.783	11,608,789
Nov-16	OTHER	--	0			0	0.000	0.000	0
Est	Osprey (Calpine)	--	133,724			133,724	3.672	3.672	4,910,265
	SHADY HILLS	--	4,592			4,592	5.328	5.328	244,663
	SOCO Franklin	--	19,248			19,248	5.418	5.418	1,042,762
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	30,501			30,501	5.732	5.732	1,748,249
	TOTAL		188,065	0	0	188,065	4.225	4.225	7,945,939
Dec-16	OTHER	--	0			0	0.000	0.000	0
Est	Osprey (Calpine)	--	77,629			77,629	3.717	3.717	2,885,546
	SHADY HILLS	--	628			628	5.832	5.832	36,610
	SOCO Franklin	--	20,356			20,356	5.394	5.394	1,097,972
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	4,418			4,418	5.769	5.769	254,850
	TOTAL		103,030	0	0	103,030	4.149	4.149	4,274,978
Jan-16	OTHER	--	0			0	0.000	0.000	0
THRU	Osprey (Calpine)	--	1,485,359			1,485,359	3.236	3.236	48,061,746
Dec-16	SHADY HILLS	--	914,192			914,192	4.304	4.304	39,343,674
	SOCO Franklin	--	1,506,106			1,506,106	2.719	2.719	40,944,447
	SOCO Scherer	--	5,559			5,559	4.590	4.590	255,163
	Vandolah (NSG)	--	1,405,314			1,405,314	4.483	4.483	62,997,683
TOTAL			5,316,530	0	0	5,316,530	3.604	3.604	191,602,712

Duke Energy Florida
Energy Payments to Qualifying Facilities
Estimated for the Period of : January through December 2016

(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) ENERGY COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(A)
Jan-16 Act	QUAL. FACILITIES	COGEN	262,976			262,976	3.150	14.147	8,284,310
Feb-16 Act	QUAL. FACILITIES	COGEN	250,530			250,530	3.765	12.772	9,432,944
Mar-16 Act	QUAL. FACILITIES	COGEN	244,684			244,684	3.977	13.195	9,730,163
Apr-16 Act	QUAL. FACILITIES	COGEN	199,894			199,894	3.831	15.105	7,658,173
May-16 Act	QUAL. FACILITIES	COGEN	256,719			256,719	4.090	12.859	10,499,028
Jun-16 Act	QUAL. FACILITIES	COGEN	268,206			268,206	3.815	12.196	10,232,952
Jul-16 Est	QUAL. FACILITIES	COGEN	286,942			286,942	4.058	11.997	11,644,372
Aug-16 Est	QUAL. FACILITIES	COGEN	286,944			286,944	4.073	12.012	11,687,183
Sep-16 Est	QUAL. FACILITIES	COGEN	260,214			260,214	4.120	12.875	10,720,507
Oct-16 Est	QUAL. FACILITIES	COGEN	244,580			244,580	4.045	13.359	9,892,299
Nov-16 Est	QUAL. FACILITIES	COGEN	281,121			281,121	4.031	12.135	11,332,121
Dec-16 Est	QUAL. FACILITIES	COGEN	296,008			296,008	4.057	11.753	12,008,298
TOTAL	QUAL. FACILITIES	COGEN	3,138,818			3,138,818	3.923	12.787	123,122,350

Duke Energy Florida
Economy Energy Purchases
Estimated for the Period of : January through December 2016

(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-16	ECONPURCH	--	3,841	5.561	5.561	213,588	2.854	109,635	(103,953)
Act	SEPA	--	61	3.977	3.977	2,426	3.977	2,426	0
	TOTAL		3,902	5.536	5.536	216,014	2.872	112,061	(103,953)
Feb-16	ECONPURCH	--	280	(19.913)	(19.913)	(55,757)	2.197	6,151	61,909
Act	SEPA	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		280	(19.913)	(19.913)	(55,757)	2.197	6,151	61,909
Mar-16	ECONPURCH	--	6,469	3.329	3.329	215,379	5.607	362,689	147,310
Act	SEPA	--	1,438	3.493	3.493	50,227	3.493	50,227	0
	TOTAL		7,907	3.359	3.359	265,606	5.222	412,916	147,310
Apr-16	ECONPURCH	--	8,056	4.702	4.702	378,780	4.438	357,561	(21,219)
Act	SEPA	--	338	3.531	3.531	11,935	3.531	11,935	0
	TOTAL		8,394	4.655	4.655	390,715	4.402	369,496	(21,219)
May-16	ECONPURCH	--	6,203	3.743	3.743	232,201	3.672	227,758	(4,443)
Act	SEPA	--	4,960	3.517	3.517	174,444	3.517	174,444	(0)
	TOTAL		11,163	3.643	3.643	406,645	3.603	402,202	(4,443)
Jun-16	ECONPURCH	--	16,768	5.852	5.852	981,230	9.179	1,539,144	557,914
Act	SEPA	--	656	3.583	3.583	23,507	3.583	23,507	(0)
	TOTAL		17,424	5.766	5.766	1,004,737	8.968	1,562,651	557,913
Jan-16	ECONPURCH	--	41,617	4.723	4.723	1,965,421	6.25	2,602,938	637,517
THRU	SEPA	--	7,453	3.523	3.523	262,539	3.52	262,539	(1)
Jun-16									
	TOTAL		49,070	4.540	4.540	2,227,961	5.840	2,865,477	637,517

Duke Energy Florida
Economy Energy Purchases
Estimated for the Period of : January through December 2016

(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-16	ECONPURCH	--	3,006	4.411	4.411	132,587	4.941	148,502	15,915
Est	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	0
	TOTAL		6,403	4.458	4.458	285,457	4.707	301,372	15,915
Aug-16	ECONPURCH	--	2,925	5.576	5.576	163,096	6.245	182,668	19,572
Est	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	0
	TOTAL		6,322	4.998	4.998	315,966	5.307	335,538	19,572
Sep-16	ECONPURCH	--	2,400	4.362	4.362	104,664	4.885	117,228	12,564
Est	SEPA	--	3,288	4.500	4.500	147,938	4.500	147,938	0
	TOTAL		5,687	4.442	4.442	252,602	4.663	265,166	12,564
Oct-16	ECONPURCH	--	7,239	4.382	4.382	317,208	4.908	355,268	38,060
Est	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	0
	TOTAL		10,636	4.420	4.420	470,078	4.778	508,138	38,060
Nov-16	ECONPURCH	--	8,064	3.899	3.899	314,418	4.367	352,143	37,725
Est	SEPA	--	3,288	4.500	4.500	147,938	4.500	147,938	0
	TOTAL		11,352	4.073	4.073	462,356	4.405	500,081	37,725
Dec-16	ECONPURCH	--	3,160	3.673	3.673	116,039	4.113	129,960	13,921
Est	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	0
	TOTAL		6,557	4.101	4.101	268,909	4.314	282,830	13,921
Jan-16	ECONPURCH	--	68,410	4.551	4.551	3,113,433	5.684	3,888,707	775,274
THRU	SEPA	--	27,616	4.236	4.236	1,169,895	4.236	1,169,895	(1)
Dec-16									
	TOTAL		96,026	4.461	4.461	4,283,329	5.268	5,058,602	775,274

Capital Structure and Cost Rates Applied to Capital Projects
Duke Energy Florida
Estimated for the Period of : January through June 2016

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost
Common Equity	$ 4,681,853	48.76%	10.50%	5.12%
Preferred Stock	-	0.00%	0.00%	0.00%
Long Term Debt	3,672,596	38.25%	5.19%	1.98%
Short Term Debt	(90,568)	-0.94%	0.17%	0.00%
Customer Deposits - Active	182,163	1.90%	2.31%	0.04%
Customer Deposits - Inactive	1,306	0.01%	0.00%	0.00%
Deferred Tax	1,318,615	13.73%	0.00%	0.00%
Deferred Tax (FAS 109)	(164,391)	-1.71%	0.00%	0.00%
ITC	498	0.01%	0.00%	0.00%
	9,602,073	95.41%		7.15%

Total Debt	2.03%
Total Equity	5.12%

* May 2015 DEF Surveillance Report capital structure and cost rates.
* Reference: Docket Nos. 120001-EG, 120002-EI, 120007-EI, PSC Order No. 12-0425-PAA-EU, page 8
* Included for Informational purposes only. DEF 2016 Actual/Estimated True-up Filing does not currently include a capital return component

Capital Structure and Cost Rates Applied to Capital Projects
Duke Energy Florida
Estimated for the Period of : July through December 2016

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

Total Debt	1.87%
Total Equity	4.87%

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

Docket 160001-EI
Exhibit No. ____(CAM-2)
Part 2

DUKE ENERGY FLORIDA

CAPACITY COST RECOVERY

ESTIMATED / ACTUAL TRUE-UP

JANUARY THROUGH DECEMBER 2016

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
Midcourse Calculation of Projected Capacity Costs
For the Year 2016 - As filed on 02/08/16 in Docket 160001-EI

Docket No. 160001-EI
Exhibit__CAM-2, Part 2
Schedule E12-A
Page 1 of 1

		EST Jan-16	EST Feb-16	EST Mar-16	EST Apr-16	EST May-16	EST Jun-16	EST Jul-16	EST Aug-16	EST Sep-16	EST Oct-16	EST Nov-16	EST Dec-16	TOTAL
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	4,541,680	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	57,630,089
3	Orlando Cogen Limited (ORLACOGL)	4,353,900	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	57,748,714
4	Pasco County Resource Recovery (PASCOUNT)	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	20,134,200
5	Pinellas County Resource Recovery (PINCOUNT)	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	47,928,156
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	6,112,250	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	79,017,401
7	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	782,100	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	800,946	9,592,506
8	Southern Scherer	1,759,878	1,766,610	1,766,610	1,766,610	1,766,610	-	-	-	-	-	-	-	8,826,318
9	Calpine Osprey													
10	Subtotal - Base Level Capacity Costs													
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													
13	**Intermediate Production Level Capacity Costs**													
14	Southern Franklin	3,256,789	3,288,628	3,288,628	3,288,628	3,288,628	4,033,578	4,033,578	4,033,578	4,033,578	4,033,578	4,033,578	4,033,578	44,646,347
15	Schedule H Capacity Sales - NSB & RCID	(16,080)	-	-	-	-	-	-	-	-	-	-	-	(16,080)
16	Subtotal - Intermediate Level Capacity Costs	3,240,709	3,288,628	3,288,628	3,288,628	3,288,628	4,033,578	4,033,578	4,033,578	4,033,578	4,033,578	4,033,578	4,033,578	44,630,267
17	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%	
18	Intermediate Level Jurisdictional Capacity Costs	2,356,092	2,390,931	2,390,931	2,390,931	2,390,932	2,932,532	2,932,532	2,932,532	2,932,532	2,932,532	2,932,532	2,932,532	32,447,543
19	**Peaking Production Level Capacity Costs**													
20	Chattahoochee	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Shady Hills Power Company LLC	1,970,869	1,970,868	1,407,765	1,365,741	1,912,038	3,887,109	3,887,109	3,887,109	1,813,983	1,365,741	1,365,741	1,970,868	26,804,941
22	Vandolah (NSG)	2,779,771	2,792,868	2,001,752	1,979,480	2,699,316	5,565,668	5,548,960	5,504,412	2,634,348	1,940,500	1,985,048	2,792,868	38,224,991
23	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Subtotal - Peaking Level Capacity Costs	4,750,640	4,763,736	3,409,517	3,345,221	4,611,354	9,452,777	9,436,069	9,391,521	4,448,331	3,306,241	3,350,789	4,763,736	65,029,932
25	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%	
26	Peaking Level Jurisdictional Capacity Costs	4,557,004	4,569,566	3,270,545	3,208,870	4,423,395	9,067,482	9,051,455	9,008,723	4,267,017	3,171,479	3,214,211	4,569,566	62,379,312
27	**Other Capacity Costs**													
28	Retail Wheeling	(50,295)	(51,556)	(22,630)	(17,044)	(28,893)	(20,294)	(25,120)	(20,904)	(9,191)	(4,756)	(22,021)	(14,539)	(287,244)
29	Batch 19 Nuclear Fuel													
30	January 2016 True-Up Balance Adjustment	14,191,484												
31	**Total Capacity Costs (Line 12+18+26+28+29+30)**	44,159,642	31,245,749	29,975,654	29,919,565	31,122,243	34,675,614	34,654,761	34,616,245	29,886,252	28,795,149	28,820,616	30,125,394	387,996,884
32	Estimated/Actual True-Up Provision - Jan - Dec 2015													35,762,070
33	**Total Capacity Costs w/ True-Up**													423,758,954
34	Revenue Tax Multiplier													1.00072
35	**Total Recoverable Capacity Costs**													424,064,061
36	**Nuclear Cost Recovery Clause**													56,469,745
37	Revenue Tax Multiplier													1.00072
38	**Total Recoverable Nuclear Costs**													56,510,403
39	**Total Recov Capacity & Nuclear Costs (Line 35+38)**													480,574,464
40	**Total Recov Capacity & Nuclear Costs - as approved in Order No. PSC-15-0586-FOF-EI**													454,282,819
41	**Proposed Adjustment (Line 39 - Line 40)**													26,291,645

Duke Energy Florida
Calculation of Estimated/Actual True-up
For the Year 2016

Docket No. 160001-EI
Exhibit__CAM-2, Part 2
Schedule E12-B

		ACT Jan-16	ACT Feb-16	ACT Mar-16	ACT Apr-16	ACT May-16	ACT Jun-16	EST Jul-16	EST Aug-16	EST Sep-16	EST Oct-16	EST Nov-16	EST Dec-16	TOTAL
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	3,266,545	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	56,354,954
3	Orlando Cogen Limited (ORLACOGL)	13,409,604	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	66,804,417
4	Pasco County Resource Recovery (PASCOUNT)	1,577,570	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	20,033,920
5	Pinellas County Resource Recovery (PINCOUNT)	3,755,303	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	47,689,443
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	6,306,018	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	79,211,169
7	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	603,090	584,735	575,947	555,284	532,520	498,053	800,946	800,946	800,946	800,946	800,946	800,946	8,155,306
8	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Southern - Scherer	2,149,228	1,826,729	1,773,417	1,774,164	1,775,120	276,573	-	-	-	-	-	-	9,575,232
10	Calpine Osprey													
11	Subtotal - Base Level Capacity Costs													
12	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%	
13	Base Level Jurisdictional Capacity Costs													
14	**Intermediate Production Level Capacity Costs**													
15	Southern - Franklin	3,201,566	3,298,621	3,206,417	3,469,625	3,102,253	5,095,516	3,977,920	3,977,920	3,977,920	3,977,920	3,977,920	3,977,920	45,241,518
16	Schedule H Capacity Sales - NSB	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Subtotal - Intermediate Level Capacity Costs	3,201,566	3,298,621	3,206,417	3,469,625	3,102,253	5,095,516	3,977,920	3,977,920	3,977,920	3,977,920	3,977,920	3,977,920	45,241,518
19	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%	
20	Intermediate Level Jurisdictional Capacity Costs	2,327,635	2,398,196	2,331,161	2,522,522	2,255,431	3,704,593	2,892,067	2,892,067	2,892,067	2,892,067	2,892,067	2,892,067	32,891,940
21	**Peaking Production Level Capacity Costs**													
22	Chattahoochee	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Vandolah (RRI)	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Shady Hills Power Company LLC	1,410,667	1,671,610	1,406,700	1,366,200	1,886,760	3,855,600	3,887,109	3,887,109	1,813,983	1,365,741	1,365,741	1,970,868	25,888,088
25	Vandolah (NSG)	2,888,436	2,892,622	2,035,755	1,947,188	2,800,279	5,784,009	5,548,960	5,504,412	2,634,348	1,940,500	1,985,048	2,792,868	38,754,425
26	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Subtotal - Peaking Level Capacity Costs	4,299,103	4,564,232	3,442,455	3,313,388	4,687,039	9,639,609	9,436,069	9,391,521	4,448,331	3,306,241	3,350,789	4,763,736	64,642,513
28	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%	
29	Peaking Level Jurisdictional Capacity Costs	4,123,872	4,378,193	3,302,140	3,178,334	4,495,995	9,246,699	9,051,455	9,008,723	4,267,017	3,171,479	3,214,211	4,569,566	62,007,684
30	**Other Capacity Costs**													
31	Retail Wheeling	(33,737)	(1,790)	(6,527)	(149,519)	(1,545)	-	(10,552)	(9,520)	(3,987)	(3,672)	(13,683)	(6,532)	(241,063)
32	Batch 19 Nuclear Fuel													
33	Other Jurisdictional Capacity Costs													
34	**Subtotal Jurisd Capacity Costs (Line 13+20+29+33)**	36,845,611	31,001,440	29,795,934	29,701,997	30,880,285	35,657,755	34,628,864	34,587,164	29,850,991	28,755,768	28,788,489	30,092,937	380,587,235
35	**Nuclear Cost Recovery Clause Costs (net of tax)**													
36	Levy Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
37	CR3 Uprate Costs	4,861,279	4,833,013	4,804,746	4,776,479	4,748,212	4,719,946	4,691,679	4,663,412	4,635,145	4,606,878	4,578,612	4,550,345	56,469,745
38	**Total NCRC Costs - Order No. PSC-15-0586-FOF-EI**	4,861,279	4,833,013	4,804,746	4,776,479	4,748,212	4,719,946	4,691,679	4,663,412	4,635,145	4,606,878	4,578,612	4,550,345	56,469,745
39	**Total Jurisdictional Capacity Costs (Line 34+38)**	41,706,890	35,834,453	34,600,679	34,478,476	35,628,497	40,377,701	39,320,542	39,250,575	34,486,136	33,362,646	33,367,101	34,643,282	437,056,980
40	**Capacity Revenues**													
41	Capacity Cost Recovery Revenues (net of tax)	33,281,758	33,857,575	32,975,595	34,435,237	40,699,538	46,120,530	48,253,503	48,974,879	49,176,389	45,339,440	37,855,002	36,604,066	487,573,513
42	Prior Period True-Up Provision Over/(Under) Recovery	(3,220,271)	(3,220,271)	(3,220,271)	(2,900,148)	(2,900,139)	(2,900,139)	(2,900,139)	(2,900,139)	(2,900,139)	(2,900,139)	(2,900,139)	(2,900,135)	(35,762,070)
43	**Current Period Revenues (net of tax)**	30,061,487	30,637,304	29,755,324	31,535,089	37,799,399	43,220,391	45,353,364	46,074,740	46,276,250	42,439,301	34,954,863	33,703,931	451,811,442
44	**True-Up Provision**													
45	True-Up Provision - Over/(Under) Recov (Line 43-39)	(11,645,403)	(5,197,149)	(4,845,356)	(2,943,386)	2,170,902	2,842,690	6,032,821	6,824,164	11,790,113	9,076,655	1,587,762	(939,350)	14,754,463
46	Interest Provision for the Month	(13,312)	(15,364)	(16,922)	(15,793)	(13,154)	(12,389)	(4,367)	(2,860)	(584)	1,273	1,969	2,274	(89,229)
47	Current Cycle Balance - Over/(Under)	(11,658,715)	(16,871,228)	(21,733,506)	(24,692,684)	(22,534,936)	(19,704,635)	(13,676,181)	(6,854,877)	4,934,652	14,012,580	15,602,311	14,665,234	14,665,234
48	Prior Period Balance - Over/(Under) Recovered	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)
49	Prior Period Cumulative True-Up Collected/(Refunded)	3,220,271	6,440,543	9,660,814	12,560,962	15,461,101	18,361,240	21,261,379	24,161,518	27,061,657	29,961,796	32,861,935	35,762,070	35,762,070
50	Prior Period True-up Balance - Over/(Under)	(32,541,799)	(29,321,528)	(26,101,256)	(23,201,108)	(20,300,969)	(17,400,830)	(14,500,691)	(11,600,552)	(8,700,413)	(5,800,274)	(2,900,135)	(0)	(0)
51	**Net Capacity True-up Over/(Under) (Line 47+50)**	($44,200,514)	($46,192,755)	($47,834,762)	($47,893,792)	($42,835,905)	($37,105,465)	($28,176,872)	($18,455,429)	($3,765,761)	$8,212,306	$12,702,176	$14,665,234	$14,665,234

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	74.00
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	Dec-23	QF	Purch	39.60
7	Florida Power Development	May-14	May-34	QF	Purch	60.00
8	Southern - Franklin	Jun-10	May-16	Other	Purch	350.00
9	Southern - Franklin	Jun-16	May-21	Other	Purch	425.00
10	Southern Wholesale - Scherer 3	Jun-10	May-16	Other	Purch	73.00
11	Schedule H Capacity - New Smyrna Beach	Nov-85	see note (1)	Other	Sale	1.00
12	Chattahoochee	Jan-03	Dec-17	Other	Purch	5.25
13	Vandolah (NSG)	Jun-12	May-27	Other	Puch	655.00
14	Shady Hills Tolling Agreement	Apr-07	Apr-24	Other	Purch	515.00
15	Calpine Osprey	Oct-14	Dec-16	Other	Purch	599.00

(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
Variance Analysis
For the Year 2016

Docket No. 160001-EI
Exhibit__CAM-2, Part 2
Schedule E12-C
Page 1 of 1

		Re-Projection Total	Midcourse Projection Total	Variance Total
1	**Capacity Revenues**			
2	Capacity Cost Recovery Revenues (net of tax)	$487,573,513	$480,228,699	$7,344,813
3	Prior Period True-Up Provision Over/(Under) Recovery	(35,762,070)	(35,762,070)	0
4	**Current Period Revenues (net of tax)**	451,811,442	444,466,629	7,344,813
5				
6	**Capacity Costs**			
7	**Base Production Level Capacity Costs**			
8	Orange Cogen (ORANGECO)	56,354,954	57,630,089	(1,275,135)
9	Orlando Cogen Limited (ORLACOGL)	66,804,417	57,748,714	9,055,703
10	Pasco County Resource Recovery (PASCOUNT)	20,033,920	20,134,200	(100,280)
11	Pinellas County Resource Recovery (PINCOUNT)	47,689,443	47,928,156	(238,713)
12	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	79,211,169	79,017,401	193,768
13	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	8,155,306	9,592,506	(1,437,200)
14	Southern - Sherer	9,575,232	8,826,318	748,914
15	Calpine Osprey	[redacted]	[redacted]	[redacted]
16	Subtotal - Base Level Capacity Costs	[redacted]	[redacted]	[redacted]
17	Base Production Jurisdictional Responsibility	92.885%	92.885%	0.000%
18	Base Level Jurisdictional Capacity Costs	[redacted]	[redacted]	[redacted]
19				
20	**Intermediate Production Level Capacity Costs**			
21	Southern - Franklin	45,241,518	44,646,347	595,171
22	Schedule H Capacity Sales - NSB & RCID	0	(16,080)	16,080
23	Subtotal - Intermediate Level Capacity Costs	45,241,518	44,630,267	611,251
24	Intermediate Production Jurisdictional Responsibility	72.703%	72.703%	0.000%
25	Intermediate Level Jurisdictional Capacity Costs	32,891,940	32,447,543	444,397
26				
27	**Peaking Production Level Capacity Costs**			
28	Chattahoochee	0	0	0
29	Vandolah (RRI)	0	0	0
30	Shady Hills Power Company LLC	25,888,088	26,804,941	(916,854)
31	Vandolah (NSG)	38,754,425	38,224,991	529,434
32	Subtotal - Peaking Level Capacity Costs	64,642,513	65,029,932	(387,420)
33	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	0.000%
34	Peaking Level Jurisdictional Capacity Costs	62,007,684	62,379,312	(371,628)
35				
36	**Other Capacity Costs**			
37	Retail Wheeling	(241,063)	(287,244)	46,181
38	Batch 19 Nuclear Fuel	[redacted]	[redacted]	[redacted]
39	January 2016 True-Up Balance Adjustment	0	14,191,484	(14,191,484)
40	Other Jurisdictional Capacity Costs	[redacted]	[redacted]	[redacted]
41				
42	**Subtotal Jurisdictional Capacity Costs (Line 18+25+34+40)**	94,658,561	108,731,096	(14,072,534)
43				
44	**Nuclear Cost Recovery Clause Costs**			
45	Levy Costs	0	0	0
46	CR3 Uprate Costs	56,469,745	56,469,745	0
47	**Total NCRC Costs - Order No. PSC-15-0586-FOF-EI**	56,469,745	56,469,745	0
48				
49	**Total Jurisdictional Capacity Costs (Line 42+47)**	151,128,306	165,200,840	(14,072,534)
50				
51	**True-Up Provision**			
52	True-Up Provision - Over/(Under) Recov (Line 4-49)	14,754,463	0	14,754,463
53	Interest Provision for the Month	(89,229)	0	(89,229)
54	Current Cycle Balance - Over/(Under)	14,665,234	0	14,665,234
55				
56	Prior Period Balance - Over/(Under) Recovered	(35,762,070)	(35,762,070)	0
57	Prior Period Cumulative True-Up Collected/(Refunded)	35,762,070	35,762,070	(0)
58	Prior Period True-up Balance - Over/(Under)	0	0	0
59				
60	**Net Capacity True-up Over/(Under) (Line 54+58)**	$14,665,234	$0	$14,665,234

Docket 160001-EI
Exhibit No. ____(CAM-3)
Part 1

DUKE ENERGY FLORIDA

FUEL AND CAPACITY COST RECOVERY FACTOR

JANUARY THROUGH DECEMBER 2017

PART 1 – 2017 FUEL PRICE FORECAST ASSUMPTIONS

Projected Market Price by Fuel Type

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 7
PARTY: DUKE ENERGY FLORIDA, LLC – (DIRECT)
DESCRIPTION: Christopher A. Menendez CAM-3

PROJECTED MARKET PRICE BY FUEL TYPE

	Light Oil		Coal Crystal River 1 & 2		Coal Crystal River 4 & 5		Natural Gas
Month	**$/barrel**	**$/mmbtu**	**$/ton**	**$/mmbtu**	**$/ton**	**$/mmbtu**	**$/mmbtu**
Jan 2017	60.06	10.36	90.13	3.82	69.78	3.07	3.04
Feb 2017	60.74	10.48	90.13	3.82	68.42	3.01	3.04
Mar 2017	61.33	10.58	90.13	3.82	66.33	2.92	2.99
Apr 2017	61.39	10.59	90.13	3.82	65.11	2.87	2.80
May 2017	61.76	10.66	90.25	3.82	63.93	2.82	2.79
Jun 2017	62.24	10.74	91.27	3.87	63.01	2.78	2.82
Jul 2017	62.49	10.78	92.14	3.92	62.02	2.74	2.86
Aug 2017	62.96	10.86	92.80	3.95	61.29	2.71	2.87
Sep 2017	63.36	10.93	93.25	3.97	60.78	2.69	2.86
Oct 2017	63.64	10.98	93.39	3.98	60.59	2.68	2.89
Nov 2017	63.33	10.93	93.40	3.98	60.54	2.68	2.96
Dec 2017	62.66	10.81	93.40	3.98	60.23	2.66	3.10
Average	62.16	10.73	91.70	3.90	63.50	2.80	2.92

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 current hedge positions and transportation costs.

Coal: Coal price projections are based on the current coal supply, transportation agreements, and forecasted deliveries. It assumes environmental restrictions on coal quality remain in effect as per current permits: 2.1 lbs. per million BTU sulfur dioxide limit for Crystal River Units 1 and 2. Crystal River 4 and 5 have operating scrubbers which allow for consideration of higher sulfur coal.

Natural Gas: The base market natural gas price forecast is the NYMEX Henry Hub forwards. This table includes natural gas market commodity prices only; however, the fuel forecast incorporates hedges and transportation costs. Forecast prices are based on expected contract specifications and incorporate current hedge positions. Firm transportation costs for Florida Gas Transmission and Gulfstream pipeline are based on expected tariff rates and/or negotiated rates. Interruptible transportation rates and availability are based on expected tariff rates and market conditions.

Docket 160001-EI
Exhibit No. ____(CAM-3)
Part 2

DUKE ENERGY FLORIDA

FUEL COST RECOVERY

JANUARY THROUGH DECEMBER 2017

PART 2 - 2017 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

Docket No. 160001-EI
Schedule E1
Exhibit CAM-3, Part 2

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January through December 2017

			DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)		1,221,838,538	37,020,131	3.3005
2.	Spent Nuclear Fuel Disposal Cost		0	0 *	0.0000
3.	Coal Car Investment		0	0	0.0000
4.	Adjustment to Fuel Cost		0	0	0.0000
5.	TOTAL COST OF GENERATED POWER		1,221,838,538	37,020,131	3.3005
6.	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)		73,811,326	1,760,693	4.1922
7.	Energy Cost of Economy Purchases (E9)		4,417,649	97,274	4.5415
8.	Payments to Qualifying Facilities (E8)		140,596,014	3,329,832	4.2223
9.	TOTAL COST OF PURCHASED POWER		218,824,989	5,187,798	4.2181
10.	TOTAL AVAILABLE MWH			42,207,929	
11.	Fuel Cost of Economy Sales	(E6)	(2,516,281)	(82,705)	3.0425
11a.	Gain on Economy Sales	(E6)	(612,488)	(82,705) *	0.7406
12.	Fuel Cost of Stratified Sales	(E6)	(23,804,974)	(956,306)	2.4893
13.	TOTAL FUEL COST AND GAINS ON POWER SALES		(26,933,743)	(1,039,011)	2.5922
14.	Net Inadvertent Interchange				
15.	TOTAL FUEL AND NET POWER TRANSACTIONS		1,413,729,784	41,168,918	3.4340
16.	Net Unbilled		(15,998,686) *	465,894	(0.0406)
17.	Company Use		5,357,002 *	(156,000)	0.0136
18.	T & D Losses		70,545,065 *	(2,054,328)	0.1789
19.	Adjusted System Sales		1,413,729,784	39,424,485	3.5859
20.	Wholesale Sales (Excluding Supplemental Sales)		(7,543,808)	(210,449)	3.5846
21.	Jurisdictional Sales		1,406,185,977	39,214,036	3.5859
22.	Jurisdictional Sales Adjusted for Line Losses x	1.0004	1,406,748,451	39,214,036	3.5874
23.	Prior Period True-Up (Sch E1-A)		26,217,663	39,214,036	0.0669
24.	Total Jurisdictional Fuel Cost		1,432,966,114	39,214,036	3.6542
25.	Revenue Tax Factor		1,031,736		1.0007
26.	Fuel Cost Adjusted for Taxes		1,433,997,850	39,214,036	3.6568
27.	GPIF **		2,255,421	39,214,036	0.0058
28.	Fuel Factor Adjusted for taxes including GPIF		1,436,253,271	39,214,036	3.6626
29.	Total Fuel Cost Factor (rounded to the nearest .001 cents/ KWH)				3.663

* For Informational Purposes Only

** Based on Jurisdictional Sales

Duke Energy Florida
Calculation of Total True-Up
(Projected Period)
Estimated for the Period of : January through December 2017

1.	Actual Over/(Under) Recovery January - December 2015. **(** Schedule E1-B, Page 2 of 2, Section C, Line 9 - Dec '15 **)**	$	116,563,080
2.	Midcourse (Over)/Under Recovery January - December 2015 . (Refunded)/Collected January - December 2016. **(** Schedule E1-B, Page 2 of 2, Section C, Line 10 - Dec '15 **)**	$	(116,588,896)
3.	Estimated Over/(Under) Recovery January - December 2016 **(** Schedule E1-B, Page 2 of 2, Section C, Lines 8 and 12 - Dec '16 **)**	$	(26,191,847)
4.	Total Over/(Under) Recovery to be Included in the January - December 2017 Projected Period **(** Lines 1 through 3 **)**	$	(26,217,663)
5.	Jurisdictional mWh Sales (Projected Period)	mWh	39,214,036
6.	True-Up Factor (Line 4 / Line 5)	Cents/kWh	0.067

CALCULATION OF ESTIMATED TRUE-UP
(6 MONTHS ACTUAL, 6 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2016

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 94,981,804	$ 83,413,721	$ 78,345,839	$ 82,817,723	$ 90,802,680	$ 110,507,482	$ 540,869,249
	2	Fuel Cost of Power Sold	(2,691,656)	(1,345,614)	(1,423,831)	(2,132,788)	(1,895,385)	(4,198,390)	(13,687,665)
	3	Fuel Cost of Purchased Power	4,937,035	6,217,173	14,421,739	20,084,233	32,818,134	31,608,698	110,087,011
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	8,284,310	9,432,944	9,730,163	7,658,173	10,499,028	10,232,952	55,837,571
	4	Energy Cost of Economy Purchases	216,014	(55,757)	265,606	390,715	406,645	1,004,737	2,227,961
	5	Adjustments to Fuel Cost	(24,885)	(26,759)	(31,140)	(30,128)	32,448	(21,508)	(101,972)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	105,702,622	97,635,708	101,308,376	108,787,927	132,663,550	149,133,972	695,232,155
B	1	Jurisdictional MWH Sales	2,772,355	2,712,018	2,687,916	2,710,583	3,189,901	3,609,509	17,682,282
	2	Non-Jurisdictional MWH Sales	30,873	20,634	21,753	74,556	23,060	28,457	199,333
	3	TOTAL SALES (Lines B1 + B2)	2,803,228	2,732,653	2,709,669	2,785,139	3,212,961	3,637,966	17,881,616
	4	Jurisdictional % of Total Sales (Line B1/B3)	98.90%	99.24%	99.20%	97.32%	99.28%	99.22%	98.89%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	98,935,994	97,150,007	94,743,489	78,832,246	94,121,778	108,162,345	571,945,858
	1a	RRSSA Refund - $60M	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	30,000,000
	1b	RRSSA Fuel Adjustment	-	-	-	-	-	-	-
	1c	RRSSA Refund - $10M	833,333	833,333	833,333	833,333	833,333	833,333	5,000,000
	2	True-Up Provision	6,560,919	6,560,919	6,560,919	10,764,480	10,764,480	10,764,480	51,976,199
	2a	Incentive Provision	717,816	717,816	717,816	717,816	717,816	717,816	4,306,896
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	112,048,062	110,262,076	107,855,558	96,147,876	111,437,408	125,477,974	663,228,953
	4	Fuel & Net Power Transactions (Line A6)	105,702,622	97,635,708	101,308,376	108,787,927	132,663,550	149,133,972	695,232,155
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	104,594,254	96,944,061	100,538,108	105,914,760	131,761,056	148,029,915	687,782,154
	6	Over/(Under) Recovery (Line C3 - Line C5)	7,453,809	13,318,014	7,317,449	(9,766,884)	(20,323,648)	(22,551,941)	(24,553,201)
	7	Interest Provision	38,614	41,097	44,882	37,893	25,826	17,633	205,945
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	7,492,423	13,359,111	7,362,331	(9,728,990)	(20,297,822)	(22,534,308)	(24,347,255)
	9	Plus: Prior Period Balance	116,563,080	116,563,080	116,563,080	116,563,080	116,563,080	116,563,080	116,563,080
	10	Plus: Cumulative True-Up Provision	(6,560,919)	(13,121,839)	(19,682,758)	(30,447,238)	(41,211,719)	(51,976,199)	(51,976,199)
	11	Subtotal Prior Period True-up	110,002,161	103,441,241	96,880,322	86,115,842	75,351,361	64,586,881	64,586,881
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	$117,494,583	124,292,775	$125,094,187	$104,600,716	$73,538,414	$40,239,626	40,239,626

CALCULATION OF ESTIMATED TRUE-UP
(6 MONTHS ACTUAL, 6 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2016

			JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 104,953,817	$ 107,346,359	$ 104,419,313	$ 98,063,519	$ 83,543,398	$ 92,467,952	$ 1,131,663,607
	2	Fuel Cost of Power Sold	(2,540,491)	(2,584,887)	(2,111,545)	(1,805,691)	(1,522,351)	(1,698,236)	(25,950,865)
	3	Fuel Cost of Purchased Power	20,235,740	20,086,620	17,363,635	11,608,789	7,945,939	4,274,978	191,602,712
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	11,644,372	11,687,183	10,720,507	9,892,299	11,332,121	12,008,298	123,122,350
	4	Energy Cost of Economy Purchases	285,457	315,966	252,602	470,078	462,356	268,909	4,283,329
	5	Adjustments to Fuel Cost	(4,357,619)	(20,508)	(18,630)	(16,142)	(12,413)	2,316	(4,524,968)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	130,221,276	136,830,734	130,625,882	118,212,851	101,749,050	107,324,217	1,420,196,164
B	1	Jurisdictional MWH Sales	3,746,390	3,802,397	3,818,043	3,520,143	2,939,053	2,841,931	38,350,239
	2	Non-Jurisdictional MWH Sales	22,211	24,219	21,223	18,003	12,892	17,383	315,264
	3	TOTAL SALES (Lines B1 + B2)	3,768,601	3,826,616	3,839,266	3,538,146	2,951,945	2,859,314	38,665,503
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.41%	99.37%	99.45%	99.49%	99.56%	99.39%	99.18%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	111,627,849	113,309,102	113,778,746	104,836,277	87,392,895	84,477,439	1,187,368,166
	1a	RRSSA Refund - $60M	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	60,000,000
	1b	RRSSA Fuel Adjustment	-	-	-	-	-	-	-
	1c	RRSSA Refund - $10M	833,333	833,333	833,333	833,333	833,333	833,333	10,000,000
	2	True-Up Provision	10,764,480	10,764,480	10,764,480	10,764,480	10,764,480	10,790,295	116,588,896
	2a	Incentive Provision	717,816	717,816	717,816	717,816	717,816	717,821	8,613,797
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	128,943,479	130,624,732	131,094,376	122,151,906	104,708,525	101,818,889	1,382,570,859
	4	Fuel & Net Power Transactions (Line A6)	130,221,276	136,830,734	130,625,882	118,212,851	101,749,050	107,324,217	1,420,196,164
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	129,504,751	136,023,087	129,959,403	117,657,009	101,341,875	106,712,207	1,408,980,487
	6	Over/(Under) Recovery (Line C3 - Line C5)	(561,273)	(5,398,356)	1,134,973	4,494,897	3,366,650	(4,893,319)	(26,409,628)
	7	Interest Provision	10,719	6,461	2,466	2	(2,116)	(5,695)	217,781
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(550,554)	(5,391,894)	1,137,438	4,494,899	3,364,533	(4,899,014)	(26,191,847)
	9	Plus: Prior Period Balance	116,563,080	116,563,080	116,563,080	116,563,080	116,563,080	116,563,080	116,563,080
	10	Plus: Cumulative True-Up Provision	(62,740,679)	(73,505,160)	(84,269,640)	(95,034,120)	(105,798,601)	(116,588,896)	(116,588,896)
	11	Subtotal Prior Period True-up	53,822,401	43,057,920	32,293,440	21,528,960	10,764,479	(25,816)	(25,816)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	$28,924,591	$12,768,217	$3,141,175	($3,128,407)	($10,528,354)	($26,217,663)	($26,217,663)

Duke Energy Florida
Calculation of Generating Performance Incentive
And True-Up Adjustment Factors
Estimated for the Period of : January through December 2017

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward / (Penalty)	$	2,255,421
	B. True-Up (Over) / Under Recovery	$	26,217,663
2.	JURISDICTIONAL mWh SALES	mWh	39,214,036
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor	Cents/kWh	0.006
	B. True-Up Factor	Cents/kWh	0.067

Duke Energy Florida
Calculation of Levelized Fuel Adjustment Factors
Estimated for the Period of : January through December 2017

1.	Period Jurisdictional Fuel Cost (Schedule E-1, line 22)	$	1,406,748,451	
1a.	Prior Period True-up (E1, Line 23)	$	26,217,663	
2.	Regulatory Assessment Fee (E1, Line 25)	$	1,031,736	
3.	Generating Performance Incentive Factor (GPIF) (E1, Line 27)	$	2,255,421	
4.	Total amount to be Recovered	$	1,436,253,271	
5.	Jurisdictional Sales (January - December 2017)		39,214,036	mWh
6.	Jurisdictional Cost per kWh Sold (Line 4 / Line 5 / 10)		3.663	Cents/kWh
7.	Effective Jurisdictional Sales (See Below)		39,166,332	mWh
	LEVELIZED FUEL FACTORS:			
8.	Fuel Factor at Secondary Metering (Line 4 / Line 7 / 10)		3.667	Cents/kWh
9.	Fuel Factor at Primary Metering		3.630	Cents/kWh
10.	Fuel Factor at Transmission Metering		3.594	Cents/kWh
	TIERED FUEL FACTORS:			
11	Fuel Factor - First Tier (0-1000 kWh)		3.377	Cents/kWh
12	Fuel Factor - Second Tier (Over 1000 kWh)		4.377	Cents/kWh

	JURISDICTIONAL SALES (mWh)	
METERING VOLTAGE:	METER	SECONDARY
Distribution Secondary	34,732,093	34,732,093
Distribution Primary	4,193,265	4,151,332
Transmission	288,680	282,906
Total	39,214,038	39,166,332

Duke Energy Florida
Calculation of Final Fuel Cost Factors
Estimated for the Period of : January through December 2017

Line:	Metering Voltage	First Tier Factor Cents/kWh	Second Tier Factor Cents/kWh	Levelized Factors Cents/kWh	----------Time of Use---------- On-Peak Multiplier 1.247	Off-Peak Multiplier 0.885
1.	Distribution Secondary	3.377	4.377	3.667	4.573	3.245
2.	Distribution Primary	--	--	3.630	4.527	3.213
3.	Transmission	--	--	3.594	4.482	3.181
4.	Lighting Service	--	--	3.494	--	--

Line 4 calculated at secondary rate of 3.667 * (18.7% * On-Peak Multiplier 1.247 + 81.3% * Off-Peak Multiplier 0.885).

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-17	873,422	29,224,114	3.346	2,375,283	60,017,286	2.527	3,248,705	89,241,400	2.747
Feb-17	761,550	23,811,466	3.127	2,019,184	52,602,764	2.605	2,780,734	76,414,230	2.748
Mar-17	812,816	23,513,479	2.893	2,207,717	60,434,936	2.737	3,020,533	83,948,415	2.779
Apr-17	983,250	35,599,102	3.621	2,087,454	53,609,537	2.568	3,070,705	89,208,639	2.905
May-17	1,358,300	51,187,028	3.768	2,367,439	57,886,049	2.445	3,725,740	109,073,078	2.928
Jun-17	1,436,913	56,114,917	3.905	2,596,108	67,803,584	2.612	4,033,020	123,918,501	3.073
Jul-17	1,428,381	61,069,925	4.275	2,851,812	77,588,407	2.721	4,280,194	138,658,332	3.240
Aug-17	1,566,184	66,696,607	4.259	2,779,608	76,878,153	2.766	4,345,792	143,574,760	3.304
Sep-17	1,359,081	53,078,141	3.905	2,644,013	70,596,811	2.670	4,003,094	123,674,952	3.089
Oct-17	1,201,154	49,604,752	4.130	2,296,150	62,944,463	2.741	3,497,304	112,549,216	3.218
Nov-17	771,942	20,762,043	2.690	2,154,582	57,494,720	2.668	2,926,524	78,256,763	2.674
Dec-17	827,088	25,666,990	3.103	2,365,790	59,160,124	2.501	3,192,878	84,827,113	2.657
TOTAL	13,380,080	496,328,565	3.709	28,745,142	757,016,834	2.634	42,125,222	1,253,345,400	2.975

MARGINAL FUEL COST	ON-PEAK	OFF-PEAK	AVERAGE
WEIGHTING MULTIPLIER	1.247	0.885	1.000

Duke Energy Florida
Development of Jurisdictional Delivery Loss Multipliers
Based on Actual Twelve Months Ending December 31, 2015
Estimated for the Period of : January through December 2017

		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		288,867	781	289,648		0.9862055	293,700		
Distribution Primary		4,131,208	11,174	4,142,382		0.9762055	4,243,351		
Distribution Secondary		34,133,108	92,313	34,225,421		0.9467387	36,150,863		
Total Retail		38,553,183	104,268	38,657,451	99.17%	0.9500967	40,687,914	99.21%	1.00040
						4.99%			
Wholesale									
Generation Level		304,498	(11,250)	293,249		1.0000000	293,249		
Transmission		-	-	-		0.9862055	-		
Distribution Primary		30,966	(1,387)	29,578		0.9762055	30,299		
Distribution Secondary		-	-	-			-		
Total Wholesale		335,464	(12,637)	322,827	0.83%	0.9977717	323,548	0.79%	0.95260
						0.22%			
Subtotal Class		38,888,647	91,631	38,980,278	100.00%	0.9504728	41,011,462	100.00%	1.00000
						4.95%			
Non-Class									
SEPA	Transmission	22,105	-	22,105		0.9862055	22,414		
Homestead Base & Int	Generation	135,871	(6,335)	129,536		1.0000000	129,536		
SECI - Base	Generation	341,240	(3,554)	337,686		1.0000000	337,686		
Reedy Creek Base & Int	Generation	370,647	(17,281)	353,366		1.0000000	353,366		
NSB - Peaking	Generation	2,129	-	2,129		1.0000000	2,129		
SECI - Intermediate	Generation	34,925	(364)	34,561		1.0000000	34,561		
SECI - Peaking	Generation	677	(7)	670		1.0000000	670		
Interchange	Generation	180,985	-	180,985		1.0000000	180,985		
Company Use	Secondary	175,126	-	175,126		0.9467387	184,978		
Total Non-Class		1,263,704	(27,540)	1,236,164			1,246,326		
Total System		40,152,352	64,091	40,216,443		0.951693	42,257,788		

Docket No. 160001-EI
Schedule E2
Exhibit CAM-3, Part 2

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January through December 2017

			Estimated Jan-17	Estimated Feb-17	Estimated Mar-17	Estimated Apr-17	Estimated May-17	Estimated Jun-17	Estimated Jul-17	Estimated Aug-17	Estimated Sep-17	Estimated Oct-17	Estimated Nov-17	Estimated Dec-17	TOTAL
1	Fuel Cost of System Net Generation		$96,468,913	$82,466,077	$87,872,028	$85,375,316	$107,291,793	$111,149,953	$116,140,966	$117,154,699	$110,750,652	$107,900,721	$95,704,871	$103,562,549	$1,221,838,538
1a	Nuclear Fuel Disposal Cost		0	0	0	0	0	0	0	0	0	0	0	0	0
1b	Adjustments to Fuel Cost		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Fuel Cost of Power Sold		(293,948)	(193,248)	(194,137)	(325,957)	(244,693)	(209,097)	(114,697)	(190,326)	(81,602)	(81,590)	(433,168)	(153,818)	(2,516,281)
2a	Gains on Power Sales		(71,551)	(47,038)	(47,256)	(79,340)	(59,560)	(50,896)	(27,919)	(46,327)	(19,864)	(19,860)	(105,436)	(37,441)	(612,488)
2b	Fuel Cost of Stratified Sales		(1,602,253)	(1,058,435)	(1,793,288)	(2,017,970)	(2,377,019)	(2,446,981)	(2,684,330)	(2,703,432)	(2,335,392)	(1,969,320)	(1,209,264)	(1,607,290)	(23,804,974)
3	Fuel Cost of Purchased Power (Excl Economy)		1,962,180	1,072,370	3,990,930	4,898,231	5,717,238	9,019,357	11,445,908	12,556,538	9,356,711	9,989,330	2,478,737	1,323,796	73,811,326
3a	Energy Payments to Qualifying Facilities		12,177,556	11,032,109	11,823,009	11,229,874	12,066,147	11,745,616	12,199,522	12,276,250	11,889,369	10,297,653	11,450,142	12,408,768	140,596,014
4	Energy Cost of Economy Purchases		309,512	262,567	448,037	345,239	320,118	308,450	446,632	415,544	327,741	607,566	355,128	271,115	4,417,649
5	Total System Fuel & Net Power Transactions		$108,950,409	$93,534,403	$102,099,322	$99,425,393	$122,714,024	$129,516,402	$137,406,082	$139,462,946	$129,887,615	$126,724,500	$108,241,010	$115,767,679	$1,413,729,784
6	Jurisdictional mWh Sold		3,162,399	2,819,126	2,657,486	2,661,601	3,023,218	3,592,575	3,831,104	4,024,630	3,904,886	3,583,805	3,031,751	2,921,454	39,214,036
7	Jurisdictional % of Total Sales		99.42%	99.56%	99.57%	99.49%	99.42%	99.44%	99.42%	99.40%	99.46%	99.50%	99.57%	99.41%	99.47%
8	Jurisdicitonal Fuel & Net Power Transactions		108,318,497	93,122,851	101,660,295	98,918,323	122,002,282	128,791,110	136,609,127	138,626,168	129,186,222	126,090,878	107,775,573	115,084,650	1,406,185,977
9	Jurisdictional Loss Multiplier		1.00040	1.00040	1.00040	1.00040	1.00040	1.00040	1.00040	1.00040	1.00040	1.00040	1.00040	1.00040	1.00040
10	Jurisdictional Fuel & Net Power Transactions		108,361,824	93,160,100	101,700,960	98,957,891	122,051,083	128,842,627	136,663,771	138,681,618	129,237,896	126,141,314	107,818,684	115,130,684	1,406,748,451
11	Adjusted System Sales	mWh	3,181,002	2,831,659	2,669,044	2,675,245	3,040,924	3,612,781	3,853,368	4,048,886	3,926,138	3,601,835	3,044,712	2,938,890	39,424,485
12	System Cost per kWh Sold	c/kWh	3.4250	3.3031	3.8253	3.7164	4.0354	3.5849	3.5659	3.4445	3.3083	3.5183	3.5550	3.9392	3.5859
13	Jurisdictional Loss Multiplier	x	1.0004	1.0004	1.0004	1.0004	1.0004	1.0004	1.0004	1.0004	1.0004	1.0004	1.0004	1.0004	1.00040
14	Jurisdictional Cost per kWh Sold	c/kWh	3.4266	3.3046	3.8270	3.7180	4.0371	3.5864	3.5672	3.4458	3.3096	3.5198	3.5563	3.9409	3.5874
15	Prior Period True-Up	+	0.0691	0.0775	0.0822	0.0821	0.0723	0.0608	0.0570	0.0543	0.0560	0.0610	0.0721	0.0748	0.0669
16	Total Jurisdictional Fuel Expense	c/kWh	3.4957	3.3821	3.9092	3.8001	4.1094	3.6472	3.6242	3.5001	3.3656	3.5807	3.6284	4.0156	3.6542
17	Revenue Tax Multiplier	x	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
18	Recovery Factor Adjusted for Taxes	c/kWh	3.4982	3.3845	3.9120	3.8028	4.1124	3.6498	3.6269	3.5026	3.3680	3.5833	3.6310	4.0185	3.6569
19	GPIF	+	0.0059	0.0067	0.0071	0.0071	0.0062	0.0052	0.0049	0.0047	0.0048	0.0052	0.0062	0.0064	0.0058
20	Total Recovery Factor (rounded .001)	c/kWh	3.504	3.391	3.919	3.810	4.119	3.655	3.632	3.507	3.373	3.589	3.637	4.025	3.663

Duke Energy Florida

Generating System Comparative Data by Fuel Type

Estimated for the Period of : January through December 2017

			Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Subtotal
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		0	0	0	0	0	0	0
2	LIGHT OIL		336,416	331,140	282,943	354,161	364,984	325,659	1,995,303
3	COAL		28,240,918	24,446,219	26,430,916	20,346,221	28,929,952	29,375,644	157,769,870
4	GAS		67,891,579	57,688,718	61,158,169	64,674,934	77,996,857	81,448,650	410,858,907
5	NUCLEAR		0	0	0	0	0	0	0
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	96,468,913	82,466,077	87,872,028	85,375,316	107,291,793	111,149,953	570,624,080
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		0	0	0	0	0	0	0
9	LIGHT OIL		241	60	41	13	6	8	369
10	COAL		894,094	787,755	875,472	668,195	916,894	943,900	5,086,310
11	GAS		2,022,683	1,708,082	1,780,374	2,015,353	2,373,869	2,580,407	12,480,767
12	NUCLEAR		0	0	0	0	0	0	0
13	SOLAR		1,429	1,298	1,605	3,598	3,617	3,241	14,788
14	OTHER		0	0	0	0	0	0	0
15	TOTAL	MWH	2,918,447	2,497,195	2,657,492	2,687,159	3,294,386	3,527,555	17,582,234
	UNITS OF FUEL BURNED								
16	HEAVY OIL	BBL	0	0	0	0	0	0	0
17	LIGHT OIL	BBL	2,185	2,079	1,305	2,422	2,576	1,948	12,515
18	COAL	TON	400,765	353,830	395,102	308,636	426,658	437,356	2,322,347
19	GAS	MCF	15,055,796	12,672,432	13,267,285	15,402,715	18,151,858	19,691,160	94,241,246
20	NUCLEAR	MMBTU	0	0	0	0	0	0	0
21	OTHER		0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
22	HEAVY OIL		0	0	0	0	0	0	0
23	LIGHT OIL		12,740	12,114	7,598	14,101	15,003	11,342	72,898
24	COAL		9,110,066	8,035,479	8,961,300	6,994,418	9,715,706	9,950,205	52,767,174
25	GAS		15,055,796	12,672,432	13,267,285	15,402,715	18,151,858	19,691,160	94,241,246
26	NUCLEAR		0	0	0	0	0	0	0
27	OTHER		0	0	0	0	0	0	0
28	TOTAL	MMBTU	24,178,602	20,720,025	22,236,183	22,411,234	27,882,567	29,652,707	147,081,318
	GENERATION MIX (% MWH)								
29	HEAVY OIL		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
30	LIGHT OIL		0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
31	COAL		30.64%	31.55%	32.94%	24.87%	27.83%	26.76%	28.93%
32	GAS		69.31%	68.40%	67.00%	75.00%	72.06%	73.15%	70.99%
33	NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	SOLAR		0.05%	0.05%	0.06%	0.13%	0.11%	0.09%	0.08%
35	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
36	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
37	HEAVY OIL	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
38	LIGHT OIL	$/BBL	153.97	159.28	216.81	146.23	141.69	167.18	159.43
39	COAL	$/TON	70.47	69.09	66.90	65.92	67.81	67.17	67.94
40	GAS	$/MCF	4.51	4.55	4.61	4.20	4.30	4.14	4.36
41	NUCLEAR	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
43	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	LIGHT OIL		26.41	27.34	37.24	25.12	24.33	28.71	27.37
45	COAL		3.10	3.04	2.95	2.91	2.98	2.95	2.99
46	GAS		4.51	4.55	4.61	4.20	4.30	4.14	4.36
47	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
48	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
49	TOTAL	$/MMBTU	3.99	3.98	3.95	3.81	3.85	3.75	3.88
	BTU BURNED PER KWH (BTU/KWH)								
50	HEAVY OIL		0	0	0	0	0	0	0
51	LIGHT OIL		52,951	200,563	185,317	1,119,127	2,500,500	1,417,750	197,770
52	COAL		10,189	10,200	10,236	10,468	10,596	10,542	10,374
53	GAS		7,443	7,419	7,452	7,643	7,647	7,631	7,551
54	NUCLEAR		0	0	0	0	0	0	0
55	OTHER		0	0	0	0	0	0	0
56	TOTAL	BTU/KWH	8,285	8,297	8,367	8,340	8,464	8,406	8,365
	GENERATED FUEL COST PER KWH (C/KWH)								
57	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	LIGHT OIL		139.82	548.25	690.10	2810.80	6083.07	4070.74	541.32
59	COAL		3.16	3.10	3.02	3.04	3.16	3.11	3.10
60	GAS		3.36	3.38	3.44	3.21	3.29	3.16	3.29
61	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
62	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
63	TOTAL	C/KWH	3.31	3.30	3.31	3.18	3.26	3.15	3.25

Duke Energy Florida

Generating System Comparative Data by Fuel Type

Estimated for the Period of : January through December 2017

			Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		0	0	0	0	0	0	0
2	LIGHT OIL		290,364	368,505	372,783	269,987	386,250	356,069	4,039,261
3	COAL		31,955,839	31,416,565	29,149,530	18,718,186	18,119,265	23,724,082	310,853,337
4	GAS		83,894,763	85,369,629	81,228,339	88,912,548	77,199,356	79,482,398	906,945,940
5	NUCLEAR		0	0	0	0	0	0	0
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	116,140,966	117,154,699	110,750,652	107,900,721	95,704,871	103,562,549	1,221,838,538
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		0	0	0	0	0	0	0
9	LIGHT OIL		0	18	76	27	12	27	529
10	COAL		1,041,837	1,031,530	961,858	649,789	649,142	865,747	10,286,213
11	GAS		2,655,720	2,711,366	2,520,136	2,356,280	1,971,130	2,005,435	26,700,833
12	NUCLEAR		0	0	0	0	0	0	0
13	SOLAR		3,185	2,981	3,050	3,209	2,699	2,644	32,556
14	OTHER		0	0	0	0	0	0	0
15	TOTAL	MWH	3,700,743	3,745,895	3,485,119	3,009,304	2,622,983	2,873,853	37,020,131
	UNITS OF FUEL BURNED								
16	HEAVY OIL	BBL	0	0	0	0	0	0	0
17	LIGHT OIL	BBL	1,394	2,581	2,630	1,061	2,839	2,402	25,422
18	COAL	TON	480,852	475,901	444,791	299,087	294,557	390,226	4,707,761
19	GAS	MCF	20,336,850	20,743,588	19,200,406	18,089,452	14,492,163	14,779,435	201,883,140
20	NUCLEAR	MMBTU	0	0	0	0	0	0	0
21	OTHER		0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
22	HEAVY OIL		0	0	0	0	0	0	0
23	LIGHT OIL		8,125	15,038	15,317	6,180	16,529	13,991	148,078
24	COAL		10,937,231	10,819,857	10,109,282	6,773,879	6,660,354	8,822,991	106,890,768
25	GAS		20,336,850	20,743,588	19,200,406	18,089,452	14,492,163	14,779,435	201,883,140
26	NUCLEAR		0	0	0	0	0	0	0
27	OTHER		0	0	0	0	0	0	0
28	TOTAL	MMBTU	31,282,206	31,578,483	29,325,005	24,869,511	21,169,046	23,616,417	308,921,986
	GENERATION MIX (% MWH)								
29	HEAVY OIL		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
30	LIGHT OIL		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
31	COAL		28.15%	27.54%	27.60%	21.59%	24.75%	30.13%	27.79%
32	GAS		71.76%	72.38%	72.31%	78.30%	75.15%	69.78%	72.13%
33	NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	SOLAR		0.09%	0.08%	0.09%	0.11%	0.10%	0.09%	0.09%
35	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
36	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
37	HEAVY OIL	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
38	LIGHT OIL	$/BBL	208.30	142.78	141.74	254.46	136.05	148.24	158.89
39	COAL	$/TON	66.46	66.01	65.54	62.58	61.51	60.80	66.03
40	GAS	$/MCF	4.13	4.12	4.23	4.92	5.33	5.38	4.49
41	NUCLEAR	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
43	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	LIGHT OIL		35.74	24.51	24.34	43.69	23.37	25.45	27.28
45	COAL		2.92	2.90	2.88	2.76	2.72	2.69	2.91
46	GAS		4.13	4.12	4.23	4.92	5.33	5.38	4.49
47	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
48	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
49	TOTAL	$/MMBTU	3.71	3.71	3.78	4.34	4.52	4.39	3.96
	BTU BURNED PER KWH (BTU/KWH)								
50	HEAVY OIL		0	0	0	0	0	0	0
51	LIGHT OIL		0	817,283	202,874	231,461	1,343,821	514,375	280,079
52	COAL		10,498	10,489	10,510	10,425	10,260	10,191	10,392
53	GAS		7,658	7,651	7,619	7,677	7,352	7,370	7,561
54	NUCLEAR		0	0	0	0	0	0	0
55	OTHER		0	0	0	0	0	0	0
56	TOTAL	BTU/KWH	8,453	8,430	8,414	8,264	8,071	8,218	8,345
	GENERATED FUEL COST PER KWH (C/KWH)								
57	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	LIGHT OIL		0.00	2002.74	493.75	1011.19	3140.24	1309.08	764.00
59	COAL		3.07	3.05	3.03	2.88	2.79	2.74	3.02
60	GAS		3.16	3.15	3.22	3.77	3.92	3.96	3.40
61	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
62	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
63	TOTAL	C/KWH	3.14	3.13	3.18	3.59	3.65	3.60	3.30

Docket No. 160001-EI
Schedule E4
Exh bit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Jan-17

(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	1	376	691	0 2	90.65	36.8	10,910	COAL	319	TONS	23 63	7,539	32,916	4.76
2 CRYSTAL RIVER	2	500	968	0 3	97.74	38.7	10,927	COAL	448	TONS	23 61	10,577	44,519	4.60
3 CRYSTAL RIVER	4	732	416,249	76.4	89.35	85.5	10,247	COAL	187,657	TONS	22.73	4,265,445	13,220,514	3.18
4 CRYSTAL RIVER	5	712	476,186	89 9	98.06	92.0	10,136	COAL	212,341	TONS	22.73	4,826,505	14,942,969	3.14
5 ANCLOTE	1	517	36,839	9 6	88.39	44.3	11,031	GAS	406,355	MCF	1 00	406,355	2,329,658	6.32
6 ANCLOTE	2	521	117,718	30.4	97.10	31.3	10,835	GAS	1,275,450	MCF	1 00	1,275,450	5,254,163	4.46
7 AVON PARK	1-2	69	0	0 0	0.00	0.0	0	GAS	0	MCF	0 00	0	0	0.00
8 BARTOW	1-4	228	177	0.1	81.61	19.4	13,237	GAS	2,343	MCF	1 00	2,343	10,565	5.97
9 BARTOW CC	1	1279	771,030	81 0	98.06	82.6	7,109	GAS	5,481,169	MCF	1 00	5,481,169	24,716,410	3.21
10 CITRUS CC	1-2	1586	0	0 0	0.00	0.0	0	GAS	0	MCF	0 00	0	0	0.00
11 DEBARY	1-10	785	648	0.1	96.52	15.0	12,424	GAS	8,048	MCF	1 00	8,048	36,290	5.60
12 HIGGINS	1-4	129	54	0.1	92.42	20.8	15,690	GAS	841	MCF	1 00	841	3,794	7.08
13 HINES CC	1-4	2,204	1,009,996	61 6	94.84	22.6	7,060	GAS	7,130,851	MCF	1 00	7,130,851	32,155,370	3.18
14 NT CITY	1-14	1,186	3,308	0.4	95.74	8.1	12,389	GAS	40,982	MCF	1 00	40,982	184,803	5.59
15 OSPREY CC	1	505	31,908	8 5	96.13	48.2	7,814	GAS	249,337	MCF	1 00	249,337	1,124,343	3.52
16 SUWANNEE STEAM	1	67	0	0 0	0.00	0.0	0	GAS	0	MCF	0 00	0	0	0.00
17 SUWANNEE STEAM	2	66	0	0 0	0.00	0.0	0	GAS	0	MCF	0 00	0	0	0.00
18 SUWANNEE STEAM	3	67	0	0 0	0.00	0.0	0	GAS	0	MCF	0 00	0	0	0.00
19 SUWANNEE CT	1-3	200	308	0 2	99.24	41.0	12,336	GAS	3,802	MCF	1 00	3,802	17,142	5.56
20 TIGER BAY CC	1	225	15,792	9.4	92.58	97.5	8,077	GAS	127,554	MCF	1 00	127,554	575,183	3.64
21 UNIV OF FLA. CC	1	47	34,906	99 8	97.74	102.2	9,427	GAS	329,064	MCF	1 00	329,064	1,483,858	4.25
22 AVON PARK	1-2	69	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	0 00	0	0	0.00
23 BARTOW	1-4	228	0	0 0	81.61	0.0	0	LIGHT OIL	0	BBLS	0 00	0	0	0.00
24 BAYBORO	1-4	231	0	0 0	95.65	0.0	0	LIGHT OIL	0	BBLS	0 00	0	96	0.00
25 DEBARY	1-10	785	58	0.1	96.52	89.9	15,226	LIGHT OIL	150	BBLS	5 85	877	13,489	23.42
26 HIGGINS	1-4	129	0	0 0	92.42	0.0	0	LIGHT OIL	0	BBLS	0 00	0	0	0.00
27 OTHER		0	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	0 00	0	0	0.00
28 NT CITY	1-14	1,186	163	0.4	95.74	292.7	12,898	LIGHT OIL	360	BBLS	5 85	2,105	27,380	16.78
29 RIO PINAR	1	16	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	0 00	0	0	0.00
30 SUWANNEE	1-3	200	20	0 2	99.24	0.0	12,828	LIGHT OIL	44	BBLS	5.77	254	3,997	20.19
31 TURNER	1-4	199	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	0 00	0	0	0.00
32 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,631	BBLS	5 83	9,504	291,454	0.00
33 SOLAR		19	1,429	10.1	0.00	0.0	0	SOLAR	0	N/A		0	0	0.00
34 TOTAL			2,918,447									24,178,602	96,468,913	3.31

Docket No. 160001-EI
Schedule E4
Exhibit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Feb-17

	(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	1	376	0	0 0	89.64	0.0	0	COAL	0	TONS	0.00	0	4,071	0 00
2	CRYSTAL RIVER	2	500	0	0 0	96.07	0.0	0	COAL	0	TONS	0.00	0	4,071	0 00
3	CRYSTAL RIVER	4	732	385,233	75 6	92.50	84.6	10,260	COAL	174,034	TONS	22.71	3,952,313	12,022,104	3.12
4	CRYSTAL RIVER	5	712	402,522	81 2	93.57	91.2	10,144	COAL	179,796	TONS	22.71	4,083,166	12,415,973	3 08
5	ANCLOTE	1	517	20,387	5.7	87.14	39.0	11,331	GAS	231,001	MCF	1.00	231,001	1,564,216	7 67
6	ANCLOTE	2	521	96,753	26.7	92.14	30.0	10,924	GAS	1,056,957	MCF	1.00	1,056,957	4,298,956	4.44
7	AVON PARK	1-2	69	0	0 0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
8	BARTOW	1-4	228	11	0 0	82.41	0.0	13,421	GAS	153	MCF	1.00	153	696	6.11
9	BARTOW CC	1	1279	678,780	76 3	96.43	81.9	7,119	GAS	4,832,001	MCF	1.00	4,832,001	21,996,722	3 24
10	CITRUS CC	1-2	1586	0	0 0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
11	DEBARY	1-10	785	184	0 0	96.64	13.5	12,439	GAS	2,290	MCF	1.00	2,290	10,423	5 66
12	HIGG NS	1-4	129	0	0 0	91.07	0.0	0	GAS	0	MCF	0.00	0	0	0 00
13	H NES CC	1-4	2,204	850,237	55.4	94.88	22.7	7,050	GAS	5,994,120	MCF	1.00	5,994,120	27,287,037	3 21
14	INT CITY	1-14	1,186	3,097	0.4	95.37	8.0	12,413	GAS	38,444	MCF	1.00	38,444	175,010	5 65
15	OSPREY CC	1	505	17,397	4 9	97.86	48.5	7,971	GAS	138,668	MCF	1.00	138,668	631,257	3 63
16	SUWANNEE STEAM	1	67	0	0 0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
17	SUWANNEE STEAM	2	66	0	0 0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
18	SUWANNEE STEAM	3	67	0	0 0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
19	SUWANNEE CT	1-3	200	54	0 0	99.05	0.0	12,239	GAS	656	MCF	1.00	656	2,986	5 57
20	TIGER BAY CC	1	225	9,847	6 3	91.43	95.1	8,402	GAS	82,731	MCF	1.00	82,731	376,616	3 82
21	UNIV OF FLA. CC	1	47	31,334	95 8	97.14	102.1	9,428	GAS	295,411	MCF	1.00	295,411	1,344,799	4 29
22	AVON PARK	1-2	69	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
23	BARTOW	1-4	228	0	0 0	82.41	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
24	BAYBORO	1-4	231	5	0 0	95.90	0.0	13,846	LIGHT OIL	12	BBLS	6.00	72	873	16.79
25	DEBARY	1-10	785	27	0 0	96.64	0.0	14,743	LIGHT OIL	68	BBLS	5.90	401	8,395	30 86
26	HIGG NS	1-4	129	0	0 0	91.07	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
27	OTHER		0	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
28	INT CITY	1-14	1,186	22	0.4	95.37	263.0	15,670	LIGHT OIL	60	BBLS	5.85	351	8,753	39 08
29	RIO P NAR	1	16	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
30	SUWANNEE	1-3	200	6	0 0	99.05	0.0	14,107	LIGHT OIL	14	BBLS	5.64	79	2,070	36 96
31	TURNER	1-4	199	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
32	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,925	BBLS	5.82	11,211	311,049	0 00
33	SOLAR		19	1,298	9 8	0.00	0.0	0	SOLAR	0	N/A		0	0	0 00
34	TOTAL			2,497,195									20,720,025	82,466,077	3 30

Docket No. 160001-EI
Schedule E4
Exhibit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Mar-17

	(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 1	376	925	0.3	87.42	35.1	10,802	COAL	423 TONS	23.62	9,992	42,240	4.57
2	CRYSTAL RIVER 2	500	0	0.0	93 87	0 0	0	COAL	0 TONS	0.00	0	4,071	0.00
3	CRYSTAL RIVER 4	732	427,280	78.5	96.13	81 6	10,297	COAL	193,988 TONS	22.68	4,399,645	12,970,355	3.04
4	CRYSTAL RIVER 5	712	447,267	84.4	96.45	88.1	10,177	COAL	200,691 TONS	22.68	4,551,663	13,414,250	3.00
5	ANCLOTE 1	517	2,385	0.6	85 00	38.4	11,735	GAS	27,988 MCF	1.00	27,988	985,027	41.30
6	ANCLOTE 2	521	127,225	32.8	94 52	34.7	10,719	GAS	1,363,731 MCF	1.00	1,363,731	5,430,378	4.27
7	AVON PARK 1-2	69	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
8	BARTOW 1-4	228	44	0.0	82.42	0 0	13,555	GAS	591 MCF	1.00	591	2,728	6.26
9	BARTOW CC 1	1279	644,328	67.7	96.13	70 5	7,148	GAS	4,605,922 MCF	1.00	4,605,922	21,231,903	3.30
10	CITRUS CC 1-2	1586	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
11	DEBARY 1-10	785	305	0.1	95 93	13 3	12,417	GAS	3,792 MCF	1.00	3,792	17,486	5.73
12	HIGGINS 1-4	129	0	0.0	91 94	0 0	0	GAS	0 MCF	0.00	0	0	0.00
13	HINES CC 1-4	2,204	934,949	57.0	91 81	23.1	7,078	GAS	6,617,756 MCF	1.00	6,617,756	30,505,848	3.26
14	NT CITY 1-14	1,186	4,710	0.5	95 28	7.7	12,423	GAS	58,513 MCF	1.00	58,513	269,724	5.73
15	OSPREY CC 1	505	0	0.0	96 92	0 0	0	GAS	0 MCF	0.00	0	0	0.00
16	SUWANNEE STEAM 1	67	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
17	SUWANNEE STEAM 2	66	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
18	SUWANNEE STEAM 3	67	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
19	SUWANNEE CT 1-3	200	298	0.2	99 03	37 2	12,230	GAS	3,642 MCF	1.00	3,642	16,788	5.64
20	TIGER BAY CC 1	225	39,058	23.3	91 94	94 9	8,453	GAS	330,144 MCF	1.00	330,144	1,521,863	3.90
21	UNIV OF FLA. CC 1	47	27,072	77.4	97 92	102.1	9,427	GAS	255,206 MCF	1 00	255,206	1,176,424	4.35
22	AVON PARK 1-2	69	0	0.0	0 00	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
23	BARTOW 1-4	228	0	0.0	82.42	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
24	BAYBORO 1-4	231	0	0.0	95 65	0 0	0	LIGHT OIL	0 BBLS	0 00	0	96	0.00
25	DEBARY 1-10	785	8	0.1	95 93	0 0	19,750	LIGHT OIL	28 BBLS	5 64	158	5,752	71.90
26	HIGGINS 1-4	129	0	0.0	91 94	0 0	0	LIGHT OIL	0 BBLS	0 00	0	0	0.00
27	OTHER	0	0	0.0	0 00	0 0	0	LIGHT OIL	0 BBLS	0 00	0	0	0.00
28	INT CITY 1-14	1,186	33	0.5	95 28	399 9	14,364	LIGHT OIL	81 BBLS	5.85	474	10,111	30.64
29	RIO PINAR 1	16	0	0.0	0 00	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30	SUWANNEE 1-3	200	0	0.0	99 03	0 0	0	LIGHT OIL	0 BBLS		0	1,180	0.00
31	TURNER 1-4	199	0	0.0	0 00	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
32	OTHER & START UP	-	0	-	0 00	0 0	0	LIGHT OIL	1,196 BBLS	5.82	6,966	265,804	0.00
33	SOLAR	19	1,605	11.4	0 00	0 0	0	SOLAR	0 N/A		0	0	0.00
34	TOTAL		2,657,492								22,236,183	87,872,028	3.31

Docket No. 160001-EI
Schedule E4
Exhibit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Apr-17

	(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 1	376	0	0.0	84.76	0 0	0	COAL	0 TONS	0.00	0	4,121	0.00
2	CRYSTAL RIVER 2	500	1,659	0.5	96 67	41 5	10,986	COAL	772 TONS	23.61	18,226	73,743	4.45
3	CRYSTAL RIVER 4	732	258,915	49.1	87 50	84 2	10,427	COAL	119,145 TONS	22.66	2,699,829	7,871,853	3.04
4	CRYSTAL RIVER 5	712	407,621	79.5	92 64	84 3	10,491	COAL	188,719 TONS	22.66	4,276,363	12,396,504	3.04
5	ANCLOTE 1	517	73,839	19.8	89.13	56 9	10,824	GAS	799,257 MCF	1.00	799,257	3,705,126	5.02
6	ANCLOTE 2	521	133,465	35.6	93 67	38 0	10,842	GAS	1,446,983 MCF	1.00	1,446,983	5,726,678	4.29
7	AVON PARK 1-2	69	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
8	BARTOW 1-4	228	99	0.1	80 33	8.7	20,525	GAS	2,032 MCF	1.00	2,032	8,531	8.62
9	BARTOW CC 1	1279	754,545	81.9	98 67	83.1	7,274	GAS	5,488,542 MCF	1.00	5,488,542	23,046,007	3.05
10	CITRUS CC 1-2	1586	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
11	DEBARY 1-10	785	212	0.0	95.43	14 3	12,922	GAS	2,742 MCF	1.00	2,742	11,513	5.43
12	HIGGINS 1-4	129	0	0.0	92 39	0 0	0	GAS	0 MCF	0.00	0	0	0.00
13	HINES CC 1-4	2,204	935,537	59.0	94 61	22 2	7,118	GAS	6,659,407 MCF	1.00	6,659,407	27,962,389	2.99
14	NT CITY 1-14	1,186	8,621	1.0	94 81	7 8	12,806	GAS	110,400 MCF	1.00	110,400	463,566	5.38
15	OSPREY CC 1	505	31,448	8.6	97 67	72.4	7,627	GAS	239,859 MCF	1.00	239,859	1,007,151	3.20
16	SUWANNEE STEAM 1	67	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
17	SUWANNEE STEAM 2	66	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
18	SUWANNEE STEAM 3	67	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
19	SUWANNEE CT 1-3	200	315	0.2	99 33	31 5	12,229	GAS	3,851 MCF	1.00	3,851	16,170	5.13
20	TIGER BAY CC 1	225	50,546	31.2	92 00	96 8	7,863	GAS	397,443 MCF	1.00	397,443	1,668,837	3.30
21	UNIV OF FLA. CC 1	47	26,726	79.0	96 67	102.1	9,436	GAS	252,199 MCF	1.00	252,199	1,058,966	3.96
22	AVON PARK 1-2	69	0	0.0	0 00	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
23	BARTOW 1-4	228	0	0.0	80 33	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
24	BAYBORO 1-4	231	0	0.0	94 98	0 0	0	LIGHT OIL	0 BBLS	0.00	0	96	0.00
25	DEBARY 1-10	785	13	0.0	95.43	0 0	17,222	LIGHT OIL	38 BBLS	5.71	217	6,406	50.84
26	HIGGINS 1-4	129	0	0.0	92 39	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
27	OTHER	0	0	0.0	0 00	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
28	INT CITY 1-14	1,186	0	0.0	94 81	0 0	0	LIGHT OIL	0 BBLS	0.00	0	4,970	0.00
29	RIO PINAR 1	16	0	0.0	0 00	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30	SUWANNEE 1-3	200	0	0.0	99 33	0 0	0	LIGHT OIL	0 BBLS		0	1,180	0.00
31	TURNER 1-4	199	0	0.0	0 00	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
32	OTHER & START UP	-	0	-	0 00	0 0	0	LIGHT OIL	2,384 BBLS	5.82	13,884	341,509	0.00
33	SOLAR	19	3,598	26.3	0 00	0 0	0	SOLAR	0 N/A		0	0	0.00
34	TOTAL		2,687,159								22,411,234	85,375,316	3.18

Docket No. 160001-EI
Schedule E4
Exh bit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: May-17

	(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	1	376	0	0.0	90 65	0 0	0	COAL	0	TONS	0.00	0	6,009	0.00
2	CRYSTAL RIVER	2	500	113,228	30.4	95.48	31 9	11,276	COAL	54,076	TONS	23.61	1,276,732	4,883,126	4.31
3	CRYSTAL RIVER	4	732	405,188	74.4	92 58	80 3	10,469	COAL	187,282	TONS	22.65	4,241,931	12,083,701	2.98
4	CRYSTAL RIVER	5	712	398,478	75.2	95.16	79.7	10,533	COAL	185,300	TONS	22.65	4,197,043	11,957,116	3.00
5	ANCLOTE	1	517	94,910	24.7	88.71	62 2	10,988	GAS	1,042,838	MCF	1.00	1,042,838	4,794,561	5.05
6	ANCLOTE	2	521	148,300	38.3	95.16	40 2	10,778	GAS	1,598,386	MCF	1.00	1,598,386	6,554,536	4.42
7	AVON PARK	1-2	69	0	0.0	0 00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
8	BARTOW	1-4	228	31	0.0	81 53	0 0	13,981	GAS	439	MCF	1.00	439	1,884	6.00
9	BARTOW CC	1	1279	714,930	75.1	97.42	77.1	7,260	GAS	5,190,608	MCF	1.00	5,190,608	22,303,561	3.12
10	CITRUS CC	1-2	1586	0	0.0	0 00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
11	DEBARY	1-10	785	190	0.0	96.72	12.1	12,825	GAS	2,438	MCF	1.00	2,438	10,478	5.51
12	HIGGINS	1-4	129	14	0.0	92 26	0 0	16,985	GAS	231	MCF	1.00	231	993	7.30
13	HINES CC	1-4	2,204	1,128,646	68.8	93.46	21.7	7,110	GAS	8,024,244	MCF	1.00	8,024,244	34,479,433	3.05
14	NT CITY	1-14	1,186	5,229	0.6	95.41	6 8	12,833	GAS	67,103	MCF	1.00	67,103	288,338	5.51
15	OSPREY CC	1	505	215,093	57.2	98 06	64 5	7,575	GAS	1,629,366	MCF	1.00	1,629,366	7,001,234	3.25
16	SUWANNEE STEAM	1	67	0	0.0	0 00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
17	SUWANNEE STEAM	2	66	0	0.0	0 00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
18	SUWANNEE STEAM	3	67	0	0.0	0 00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
19	SUWANNEE CT	1-3	200	83	0.1	99 07	21 6	13,101	GAS	1,090	MCF	1.00	1,090	4,684	5.63
20	TIGER BAY CC	1	225	33,213	19.8	90 65	84.4	8,488	GAS	281,907	MCF	1.00	281,907	1,211,328	3.65
21	UNIV OF FLA. CC	1	47	33,230	95.0	97.10	97 9	9,425	GAS	313,208	MCF	1.00	313,208	1,345,827	4.05
22	AVON PARK	1-2	69	0	0.0	0 00	0 0	0	LIGHT O L	0	BBLS	0.00	0	0	0.00
23	BARTOW	1-4	228	0	0.0	81 53	0 0	0	LIGHT O L	0	BBLS	0.00	0	0	0.00
24	BAYBORO	1-4	231	0	0.0	95 57	0 0	0	LIGHT O L	0	BBLS	0.00	0	96	0.00
25	DEBARY	1-10	785	0	0.0	96.72	0 0	0	LIGHT O L	0	BBLS	0.00	0	4,011	0.00
26	HIGGINS	1-4	129	0	0.0	92 26	0 0	0	LIGHT O L	0	BBLS	0.00	0	0	0.00
27	OTHER		0	0	0.0	0 00	0 0	0	LIGHT O L	0	BBLS	0.00	0	0	0.00
28	NT CITY	1-14	1,186	3	0.6	95.41	0 0	16,000	LIGHT O L	8	BBLS	6.00	48	5,490	183.00
29	RIO PINAR	1	16	0	0.0	0 00	0 0	0	LIGHT O L	0	BBLS	0.00	0	0	0.00
30	SUWANNEE	1-3	200	3	0.1	99 07	0 0	17,000	LIGHT O L	9	BBLS	5.67	51	1,757	58.57
31	TURNER	1-4	199	0	0.0	0 00	0 0	0	LIGHT O L	0	BBLS	0.00	0	0	0.00
32	OTHER & START UP		-	0	-	0 00	0 0	0	LIGHT O L	2,559	BBLS	5.82	14,904	353,630	0.00
33	SOLAR		19	3,617	25.6	0 00	0 0	0	SOLAR	0	N/A		0	0	0.00
34	TOTAL			3,294,386									27,882,567	107,291,793	3.26

Docket No. 160001-EI
Schedule E4
Exhibit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Jun-17

	(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	1	376	0	0.0	93.67	0.0	0	COAL	0	TONS	0.00	0	6,039	0 00
2	CRYSTAL RIVER	2	500	119,716	33.3	97.33	34.2	11,182	COAL	56,819	TONS	23.56	1,338,667	5,186,679	4 33
3	CRYSTAL RIVER	4	732	429,130	81.4	96.00	84.8	10,416	COAL	197,510	TONS	22.63	4,469,646	12,547,041	2 92
4	CRYSTAL RIVER	5	712	395,054	77.1	92.67	83.9	10,484	COAL	183,027	TONS	22.63	4,141,892	11,635,885	2 95
5	ANCLOTE	1	517	106,349	28.6	90.00	69.5	10,814	GAS	1,150,048	MCF	1.00	1,150,048	4,970,256	4 67
6	ANCLOTE	2	521	147,644	39.4	92.00	42.8	10,704	GAS	1,580,403	MCF	1.00	1,580,403	6,323,723	4.28
7	AVON PARK	1-2	69	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
8	BARTOW	1-4	228	71	0.0	82.25	15.6	13,933	GAS	992	MCF	1.00	992	4,103	5.76
9	BARTOW CC	1	1279	735,965	79.9	98.67	80.9	7,227	GAS	5,319,132	MCF	1.00	5,319,132	22,001,556	2 99
10	CITRUS CC	1-2	1586	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
11	DEBARY	1-10	785	594	0.1	96.77	9.6	12,812	GAS	7,605	MCF	1.00	7,605	31,457	5 30
12	HIGG NS	1-4	129	13	0.0	92.17	0.0	15,313	GAS	196	MCF	1.00	196	812	6 34
13	H NES CC	1-4	2,204	1,268,522	79.9	93.42	21.7	7,132	GAS	9,046,571	MCF	1.00	9,046,571	37,419,383	2 95
14	INT CITY	1-14	1,186	10,734	1.3	96.19	6.7	12,857	GAS	138,007	MCF	1.00	138,007	570,835	5 32
15	OSPREY CC	1	505	228,976	63.0	96.67	66.7	7,535	GAS	1,725,318	MCF	1.00	1,725,318	7,136,441	3.12
16	SUWANNEE STEAM	1	67	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
17	SUWANNEE STEAM	2	66	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
18	SUWANNEE STEAM	3	67	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
19	SUWANNEE CT	1-3	200	322	0.2	99.11	26.9	13,096	GAS	4,222	MCF	1.00	4,222	17,463	5.42
20	TIGER BAY CC	1	225	48,870	30.2	91.67	84.2	8,468	GAS	413,835	MCF	1.00	413,835	1,711,747	3 50
21	UNIV OF FLA. CC	1	47	32,347	95.6	97.67	97.9	9,424	GAS	304,831	MCF	1.00	304,831	1,260,874	3 90
22	AVON PARK	1-2	69	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
23	BARTOW	1-4	228	0	0.0	82.25	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
24	BAYBORO	1-4	231	0	0.0	95.42	0.0	0	LIGHT OIL	0	BBLS	0.00	0	96	0 00
25	DEBARY	1-10	785	8	0.1	96.77	0.0	16,750	LIGHT OIL	23	BBLS	5.83	134	5,508	68 85
26	HIGG NS	1-4	129	0	0.0	92.17	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
27	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
28	INT CITY	1-14	1,186	0	0.0	96.19	0.0	0	LIGHT OIL	0	BBLS	0.00	0	4,970	0 00
29	RIO P NAR	1	16	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
30	SUWANNEE	1-3	200	0	0.0	99.11	0.0	0	LIGHT OIL	0	BBLS		0	1,180	0 00
31	TURNER	1-4	199	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
32	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,925	BBLS	5.82	11,208	313,905	0 00
33	SOLAR		19	3,241	23.7	0.00	0.0	0	SOLAR	0	N/A		0	0	0 00
34	TOTAL			3,527,555									29,652,707	111,149,953	3.15

Docket No. 160001-EI
Schedule E4
Exh bit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Jul-17

	(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	1	376	2,313	0.8	92 26	47.3	10,723	COAL	1,055	TONS	23.51	24,802	103,279	4.47
2	CRYSTAL RIVER	2	500	130,080	35.0	95 81	36.5	11,099	COAL	61,384	TONS	23.52	1,443,757	5,665,580	4.36
3	CRYSTAL RIVER	4	732	456,012	83.7	95.16	88.0	10,380	COAL	209,174	TONS	22.63	4,733,597	13,091,465	2.87
4	CRYSTAL RIVER	5	712	453,432	85.6	98 06	87.5	10,443	COAL	209,239	TONS	22.63	4,735,075	13,095,515	2.89
5	ANCLOTE	1	517	112,214	29.2	87.42	69.6	10,793	GAS	1,211,078	MCF	1.00	1,211,078	5,221,058	4.65
6	ANCLOTE	2	521	156,587	40.4	92 26	43.8	10,676	GAS	1,671,647	MCF	1.00	1,671,647	6,670,928	4.26
7	AVON PARK	1-2	69	0	0.0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
8	BARTOW	1-4	228	27	0.0	82 82	0.0	14,191	GAS	386	MCF	1.00	386	1,590	5.85
9	BARTOW CC	1	1279	741,632	77.9	98.71	79.0	7,245	GAS	5,373,386	MCF	1.00	5,373,386	22,166,604	2.99
10	CITRUS CC	1-2	1586	0	0.0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
11	DEBARY	1-10	785	1,073	0.2	96.16	11.4	12,848	GAS	13,781	MCF	1.00	13,781	56,849	5.30
12	HIGGINS	1-4	129	0	0.0	92 26	0.0	0	GAS	0	MCF	0.00	0	0	0.00
13	HINES CC	1-4	2,204	1,295,858	79.0	92 66	21.6	7,141	GAS	9,254,228	MCF	1.00	9,254,228	38,176,083	2.95
14	INT CITY	1-14	1,186	14,653	1.7	95 58	6.7	12,842	GAS	188,174	MCF	1.00	188,174	776,269	5.30
15	OSPREY CC	1	505	248,679	66.2	95.48	69.2	7,519	GAS	1,869,831	MCF	1.00	1,869,831	7,713,536	3.10
16	SUWANNEE STEAM	1	67	0	0.0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
17	SUWANNEE STEAM	2	66	0	0.0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
18	SUWANNEE STEAM	3	67	0	0.0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
19	SUWANNEE CT	1-3	200	198	0.1	99.14	24.7	13,097	GAS	2,588	MCF	1.00	2,588	10,679	5.40
20	TIGER BAY CC	1	225	51,901	31.0	91 29	84.2	8,508	GAS	441,568	MCF	1.00	441,568	1,821,582	3.51
21	UNIV OF FLA. CC	1	47	32,899	94.1	96.13	97.9	9,428	GAS	310,183	MCF	1.00	310,183	1,279,585	3.89
22	AVON PARK	1-2	69	0	0.0	0 00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
23	BARTOW	1-4	228	0	0.0	82 82	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
24	BAYBORO	1-4	231	0	0.0	96.45	0.0	0	LIGHT OIL	0	BBLS	0.00	0	96	0.00
25	DEBARY	1-10	785	0	0.0	96.16	0.0	0	LIGHT OIL	0	BBLS	0.00	0	4,011	0.00
26	HIGGINS	1-4	129	0	0.0	92 26	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
27	OTHER		0	0	0.0	0 00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
28	INT CITY	1-14	1,186	0	0.0	95 58	0.0	0	LIGHT OIL	0	BBLS	0.00	0	4,970	0.00
29	RIO PINAR	1	16	0	0.0	0 00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
30	SUWANNEE	1-3	200	0	0.0	99.14	0.0	0	LIGHT OIL	0	BBLS		0	1,180	0.00
31	TURNER	1-4	199	0	0.0	0 00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
32	OTHER & START UP		-	0	-	0 00	0.0	0	LIGHT OIL	1,394	BBLS	5.83	8,125	280,107	0.00
33	SOLAR		19	3,185	22.5	0 00	0.0	0	SOLAR	0	N/A		0	0	0.00
34	TOTAL			3,700,743									31,282,206	116,140,966	3.14

Docket No. 160001-EI
Schedule E4
Exhibit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Aug-17

	(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	1	376	2,893	1 0	92.26	48.1	10,698	COAL	1,317	TONS	23.50	30,948	128,355	4.44
2	CRYSTAL RIVER	2	500	131,111	35 2	95.16	37 0	11,081	COAL	61,847	TONS	23.49	1,452,783	5,744,603	4.38
3	CRYSTAL RIVER	4	732	449,124	82 5	92.26	89.4	10,367	COAL	205,847	TONS	22.62	4,656,270	12,739,845	2.84
4	CRYSTAL RIVER	5	712	448,402	84 6	96.13	88 3	10,437	COAL	206,890	TONS	22.62	4,679,856	12,803,762	2.86
5	ANCLOTE	1	517	166,120	43 2	92.26	46 8	10,286	GAS	1,708,749	MCF	1.00	1,708,749	6,804,340	4.10
6	ANCLOTE	2	521	111,835	28 9	89.03	72 0	10,990	GAS	1,229,058	MCF	1.00	1,229,058	5,286,120	4.73
7	AVON PARK	1-2	69	0	0 0	0.00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
8	BARTOW	1-4	228	107	0.1	81.69	23.4	13,923	GAS	1,487	MCF	1.00	1,487	6,124	5.73
9	BARTOW CC	1	1279	723,448	76 0	95.81	79 3	7,245	GAS	5,241,402	MCF	1.00	5,241,402	21,570,837	2.98
10	CITRUS CC	1-2	1586	0	0 0	0.00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
11	DEBARY	1-10	785	883	0 2	96.36	10 3	12,816	GAS	11,313	MCF	1.00	11,313	46,557	5.27
12	HIGGINS	1-4	129	38	0 0	92.82	14.7	17,407	GAS	658	MCF	1.00	658	2,708	7.16
13	HINES CC	1-4	2,204	1,339,116	81.7	94.84	21 8	7,137	GAS	9,556,917	MCF	1.00	9,556,917	39,331,216	2.94
14	NT CITY	1-14	1,186	18,653	2.1	95.58	6.7	12,834	GAS	239,392	MCF	1.00	239,392	985,206	5.28
15	OSPREY CC	1	505	257,207	68 5	97.10	71 3	7,502	GAS	1,929,572	MCF	1.00	1,929,572	7,941,096	3.09
16	SUWANNEE STEAM	1	67	0	0 0	0.00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
17	SUWANNEE STEAM	2	66	0	0 0	0.00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
18	SUWANNEE STEAM	3	67	0	0 0	0.00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
19	SUWANNEE CT	1-3	200	317	0 2	98.92	27.1	13,086	GAS	4,151	MCF	1.00	4,151	17,083	5.39
20	TIGER BAY CC	1	225	59,970	35 8	91.94	84 6	8,397	GAS	503,596	MCF	1.00	503,596	2,072,533	3.46
21	UNIV OF FLA. CC	1	47	33,672	96 3	98.39	97 9	9,423	GAS	317,293	MCF	1.00	317,293	1,305,809	3.88
22	AVON PARK	1-2	69	0	0 0	0.00	0 0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
23	BARTOW	1-4	228	0	0 0	81.69	0 0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
24	BAYBORO	1-4	231	0	0 0	95.49	0 0	0	LIGHT OIL	0	BBLS	0.00	0	96	0.00
25	DEBARY	1-10	785	4	0 2	96.36	0 0	18,372	LIGHT OIL	14	BBLS	5.64	79	4,903	114.02
26	HIGGINS	1-4	129	0	0 0	92.82	0 0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
27	OTHER		0	0	0 0	0.00	0 0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
28	NT CITY	1-14	1,186	6	2.1	95.58	0 0	15,833	LIGHT OIL	16	BBLS	5.94	95	6,030	100.50
29	RIO PINAR	1	16	0	0 0	0.00	0 0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
30	SUWANNEE	1-3	200	8	0 2	98.92	0 0	14,568	LIGHT OIL	20	BBLS	5.90	118	2,546	31.43
31	TURNER	1-4	199	0	0 0	0.00	0 0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
32	OTHER & START UP		-	0	-	0.00	0 0	0	LIGHT OIL	2,531	BBLS	5.83	14,746	354,930	0.00
33	SOLAR		19	2,981	21.1	0.00	0 0	0	SOLAR	0	N/A		0	0	0.00
34	TOTAL			3,745,895									31,578,483	117,154,699	3.13

Docket No. 160001-EI
Schedule E4
Exhibit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Sep-17

(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	1	376	5,238	1.9	92 00	38.7	10,949	COAL	2,444 TONS	23.47	57,352	233,698	4.46
2 CRYSTAL RIVER	2	500	113,994	31.7	93.79	34.9	11,152	COAL	54,166 TONS	23.47	1,271,268	5,052,947	4.43
3 CRYSTAL RIVER	4	732	427,958	81.2	93 33	87.0	10,391	COAL	196,595 TONS	22.62	4,446,982	12,083,833	2 82
4 CRYSTAL RIVER	5	712	414,668	80.9	95 00	86.7	10,451	COAL	191,586 TONS	22.62	4,333,680	11,779,052	2 84
5 ANCLOTE	1	517	143,317	38.5	89 00	43.2	10,362	GAS	1,485,029 MCF	1.00	1,485,029	6,110,142	4 26
6 ANCLOTE	2	521	103,145	27.5	97 00	66.7	11,107	GAS	1,145,599 MCF	1.00	1,145,599	5,018,872	4 87
7 AVON PARK	1-2	69	0	0.0	0 00	0.0	0	GAS	0 MCF	0.00	0	0	0 00
8 BARTOW	1-4	228	103	0.1	80 00	22.5	13,850	GAS	1,421 MCF	1.00	1,421	6,011	5 86
9 BARTOW CC	1	1279	709,320	77.0	97 00	79.3	7,247	GAS	5,140,297 MCF	1.00	5,140,297	21,746,304	3 07
10 CITRUS CC	1-2	1586	0	0.0	0 00	0.0	0	GAS	0 MCF	0.00	0	0	0 00
11 DEBARY	1-10	785	686	0.1	96 60	10.1	12,815	GAS	8,787 MCF	1.00	8,787	37,174	5.42
12 HIGG NS	1-4	129	82	0.1	92 83	15.8	16,123	GAS	1,314 MCF	1.00	1,314	5,555	6 82
13 H NES CC	1-4	2,204	1,250,560	78.8	92 97	21.7	7,144	GAS	8,934,451 MCF	1.00	8,934,451	37,797,669	3 02
14 INT CITY	1-14	1,186	8,861	1.0	95.71	6.9	12,790	GAS	113,339 MCF	1.00	113,339	479,487	5.41
15 OSPREY CC	1	505	235,084	64.7	97 33	68.0	7,527	GAS	1,769,566 MCF	1.00	1,769,566	7,486,242	3.18
16 SUWANNEE STEAM	1	67	0	0.0	0 00	0.0	0	GAS	0 MCF	0.00	0	0	0 00
17 SUWANNEE STEAM	2	66	0	0.0	0 00	0.0	0	GAS	0 MCF	0.00	0	0	0 00
18 SUWANNEE STEAM	3	67	0	0.0	0 00	0.0	0	GAS	0 MCF	0.00	0	0	0 00
19 SUWANNEE CT	1-3	200	140	0.1	99 22	39.8	13,077	GAS	1,836 MCF	1.00	1,836	7,767	5 53
20 TIGER BAY CC	1	225	50,511	31.2	91 67	84.4	8,431	GAS	425,852 MCF	1.00	425,852	1,801,590	3 57
21 UNIV OF FLA. CC	1	47	18,326	54.2	97 65	98.0	9,435	GAS	172,915 MCF	1.00	172,915	731,526	3 99
22 AVON PARK	1-2	69	0	0.0	0 00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0 00
23 BARTOW	1-4	228	0	0.0	80 00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0 00
24 BAYBORO	1-4	231	0	0.0	96 08	0.0	0	LIGHT OIL	0 BBLS	0.00	0	96	0 00
25 DEBARY	1-10	785	31	0.1	96 60	0.0	14,423	LIGHT OIL	77 BBLS	5.84	450	9,131	29 27
26 HIGG NS	1-4	129	0	0.0	92 83	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0 00
27 OTHER		0	0	0.0	0 00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0 00
28 INT CITY	1-14	1,186	26	1.0	95.71	0.0	14,078	LIGHT OIL	62 BBLS	5.79	359	9,005	35 31
29 RIO P NAR	1	16	0	0.0	0 00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0 00
30 SUWANNEE	1-3	200	19	0.1	99 22	0.0	12,979	LIGHT OIL	42 BBLS	5.81	244	4,031	21.44
31 TURNER	1-4	199	0	0.0	0 00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0 00
32 OTHER & START UP		-	0	-	0 00	0.0	0	LIGHT OIL	2,449 BBLS	5.82	14,264	350,520	0 00
33 SOLAR		19	3,050	22.3	0 00	0.0	0	SOLAR	0 N/A		0	0	0 00
34 TOTAL			3,485,119								29,325,005	110,750,652	3.18

Docket No. 160001-EI
Schedule E4
Exhibit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Oct-17

(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	1	376	21,712	7 8	91.29	39 0	10,957	COAL	10,140	TONS	23.46	237,893	951,402	4.38
2 CRYSTAL RIVER	2	500	0	0 0	96.25	0 0	0	COAL	0	TONS	0 00	0	4,588	0.00
3 CRYSTAL RIVER	4	732	456,649	83 8	96.45	86 9	10,395	COAL	209,845	TONS	22 62	4,746,702	12,844,038	2.81
4 CRYSTAL RIVER	5	712	171,428	32.4	95.00	87 9	10,438	COAL	79,102	TONS	22 62	1,789,284	4,918,158	2.87
5 ANCLOTE	1	517	152,971	39 8	90.32	44 0	10,340	GAS	1,581,721	MCF	1 00	1,581,721	7,325,991	4.79
6 ANCLOTE	2	521	94,319	24 3	95.00	69.1	11,022	GAS	1,039,545	MCF	1 00	1,039,545	5,557,955	5.89
7 AVON PARK	1-2	69	0	0 0	0.00	0 0	0	GAS	0	MCF	0 00	0	0	0.00
8 BARTOW	1-4	228	96	0.1	80.40	21.1	13,932	GAS	1,343	MCF	1 00	1,343	6,597	6.84
9 BARTOW CC	1	1279	687,564	72 3	93.73	75 6	7,223	GAS	4,966,053	MCF	1 00	4,966,053	24,408,943	3.55
10 CITRUS CC	1-2	1586	0	0 0	0.00	0 0	0	GAS	0	MCF	0 00	0	0	0.00
11 DEBARY	1-10	785	676	0.1	96.42	9 8	12,800	GAS	8,648	MCF	1 00	8,648	42,507	6.29
12 HIGGINS	1-4	129	29	0 0	91.29	11.4	18,571	GAS	546	MCF	1 00	546	2,686	9.14
13 HINES CC	1-4	2,204	1,099,973	67.1	94.14	21 8	7,210	GAS	7,930,804	MCF	1 00	7,930,804	38,981,167	3.54
14 NT CITY	1-14	1,186	10,630	1 2	95.16	6 8	12,827	GAS	136,341	MCF	1 00	136,341	670,138	6.30
15 OSPREY CC	1	505	229,408	61.1	98.06	68 6	7,517	GAS	1,724,544	MCF	1 00	1,724,544	8,476,409	3.69
16 SUWANNEE STEAM	1	67	0	0 0	0.00	0 0	0	GAS	0	MCF	0 00	0	0	0.00
17 SUWANNEE STEAM	2	66	0	0 0	0.00	0 0	0	GAS	0	MCF	0 00	0	0	0.00
18 SUWANNEE STEAM	3	67	0	0 0	0.00	0 0	0	GAS	0	MCF	0 00	0	0	0.00
19 SUWANNEE CT	1-3	200	99	0.1	99.34	25 5	13,087	GAS	1,293	MCF	1 00	1,293	6,353	6.43
20 TIGER BAY CC	1	225	47,285	28 2	92.00	85 8	8,151	GAS	385,425	MCF	1 00	385,425	1,894,427	4.01
21 UNIV OF FLA. CC	1	47	33,230	95 0	97.10	97 9	9,425	GAS	313,189	MCF	1 00	313,189	1,539,375	4.63
22 AVON PARK	1-2	69	0	0 0	0.00	0 0	0	LIGHT O L	0	BBLS	0 00	0	0	0.00
23 BARTOW	1-4	228	0	0 0	80.40	0 0	0	LIGHT O L	0	BBLS	0 00	0	0	0.00
24 BAYBORO	1-4	231	0	0 0	95.49	0 0	0	LIGHT O L	0	BBLS	0 00	0	96	0.00
25 DEBARY	1-10	785	18	0.1	96.42	0 0	14,746	LIGHT O L	45	BBLS	5 80	261	6,988	39.48
26 HIGGINS	1-4	129	0	0 0	91.29	0 0	0	LIGHT O L	0	BBLS	0 00	0	0	0.00
27 OTHER		0	0	0 0	0.00	0 0	0	LIGHT O L	0	BBLS	0 00	0	0	0.00
28 NT CITY	1-14	1,186	6	1 2	95.16	0 0	15,833	LIGHT O L	16	BBLS	5 94	95	6,041	100.68
29 RIO PINAR	1	16	0	0 0	0.00	0 0	0	LIGHT O L	0	BBLS	0 00	0	0	0.00
30 SUWANNEE	1-3	200	3	0.1	99.34	0 0	17,000	LIGHT O L	9	BBLS	5 67	51	1,773	59.10
31 TURNER	1-4	199	0	0 0	0.00	0 0	0	LIGHT O L	0	BBLS	0 00	0	0	0.00
32 OTHER & START UP		-	0	-	0.00	0 0	0	LIGHT O L	991	BBLS	5 83	5,773	255,089	0.00
33 SOLAR		19	3,209	22.7	0.00	0 0	0	SOLAR	0	N/A		0	0	0.00
34 TOTAL			3,009,304									24,869,511	107,900,721	3.59

Docket No. 160001-EI
Schedule E4
Exhibit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Nov-17

(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	1	376	0	0.0	88 00	0.0	0	COAL	0	TONS	0.00	0	4,071	0 00
2 CRYSTAL RIVER	2	500	1,010	0.3	96 00	28.9	11,109	COAL	478	TONS	23.47	11,220	48,729	4 82
3 CRYSTAL RIVER	4	732	395,849	75.1	94 33	79.6	10,311	COAL	180,514	TONS	22.61	4,081,419	11,061,596	2.79
4 CRYSTAL RIVER	5	712	252,283	49.2	95 50	86.8	10,178	COAL	113,565	TONS	22.61	2,567,715	7,004,869	2.78
5 ANCLOTE	1	517	102,329	27.5	86 33	31.8	10,374	GAS	1,061,578	MCF	1.00	1,061,578	4,648,424	4 54
6 ANCLOTE	2	521	5,000	1.3	96 92	35.5	12,496	GAS	62,482	MCF	1.00	62,482	1,339,417	26.79
7 AVON PARK	1-2	69	0	0.0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
8 BARTOW	1-4	228	60	0.0	81 92	11.9	13,356	GAS	800	MCF	1.00	800	4,262	7.12
9 BARTOW CC	1	1279	706,954	76.8	95 33	80.5	7,135	GAS	5,044,234	MCF	1.00	5,044,234	26,870,496	3 80
10 CITRUS CC	1-2	1586	0	0.0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
11 DEBARY	1-10	785	329	0.1	96 07	45.5	12,290	GAS	4,041	MCF	1.00	4,041	21,527	6 55
12 HIGGINS	1-4	129	30	0.0	91 92	0.0	15,814	GAS	476	MCF	1.00	476	2,539	8.44
13 HINES CC	1-4	2,204	1,022,881	64.5	95 00	27.9	7,056	GAS	7,217,591	MCF	1.00	7,217,591	38,447,903	3.76
14 NT CITY	1-14	1,186	6,795	0.8	95 36	15.6	12,513	GAS	85,031	MCF	1.00	85,031	452,957	6 67
15 OSPREY CC	1	505	90,913	25.0	96 00	63.6	7,497	GAS	681,536	MCF	1.00	681,536	3,630,524	3 99
16 SUWANNEE STEAM	1	67	0	0.0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
17 SUWANNEE STEAM	2	66	0	0.0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
18 SUWANNEE STEAM	3	67	0	0.0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
19 SUWANNEE CT	1-3	200	0	0.0	99 33	0.0	0	GAS	0	MCF		0	0	0 00
20 TIGER BAY CC	1	225	2,315	1.4	98.46	93.5	7,913	GAS	18,319	MCF	1.00	18,319	97,584	4 22
21 UNIV OF FLA. CC	1	47	33,523	99.1	97 00	100.0	9,429	GAS	316,075	MCF	1.00	316,075	1,683,723	5 02
22 AVON PARK	1-2	69	0	0.0	0 00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
23 BARTOW	1-4	228	0	0.0	81 92	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
24 BAYBORO	1-4	231	0	0.0	95 33	0.0	0	LIGHT OIL	0	BBLS	0.00	0	96	0 00
25 DEBARY	1-10	785	9	0.1	96 07	0.0	18,172	LIGHT OIL	29	BBLS	5.83	169	5,935	63 82
26 HIGGINS	1-4	129	0	0.0	91 92	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
27 OTHER		0	0	0.0	0 00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
28 NT CITY	1-14	1,186	3	0.8	95 36	0.0	17,000	LIGHT OIL	9	BBLS	5.67	51	5,542	184.73
29 RIO PINAR	1	16	0	0.0	0 00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
30 SUWANNEE	1-3	200	0	0.0	99 33	0.0	0	LIGHT OIL	0	BBLS		0	1,180	0 00
31 TURNER	1-4	199	0	0.0	0 00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
32 OTHER & START UP		-	0	-	0 00	0.0	0	LIGHT OIL	2,801	BBLS	5.82	16,309	373,497	0 00
33 SOLAR		19	2,699		0 00	0.0	0	SOLAR	0	N/A		0	0	0 00
34 TOTAL			2,622,983									21,169,046	95,704,871	3 65

Docket No. 160001-EI
Schedule E4
Exh bit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Dec-17

	(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	1	376	0	0.0	97.10	0.0	0	COAL	0	TONS	0.00	0	4,071	0.00
2	CRYSTAL RIVER	2	500	0	0.0	96.77	0.0	0	COAL	0	TONS	0.00	0	4,071	0.00
3	CRYSTAL RIVER	4	732	419,249	77.0	90.65	85.0	10,249	COAL	190,041	TONS	22.61	4,296,817	11,552,925	2.76
4	CRYSTAL RIVER	5	712	446,498	84.3	93.23	91.8	10,137	COAL	200,185	TONS	22.61	4,526,174	12,163,015	2.72
5	ANCLOTE	1	517	96,131	25.0	88.06	28.4	10,510	GAS	1,010,325	MCF	1.00	1,010,325	4,702,406	4.89
6	ANCLOTE	2	521	26,200	6.8	88.71	36.2	11,719	GAS	307,044	MCF	1.00	307,044	2,382,284	9.09
7	AVON PARK	1-2	69	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
8	BARTOW	1-4	228	0	0.0	81.13	0.0	0	GAS	0	MCF	0.00	0	0	0.00
9	BARTOW CC	1	1279	754,756	79.3	96.77	82.0	7,128	GAS	5,380,210	MCF	1.00	5,380,210	28,934,259	3.83
10	CITRUS CC	1-2	1586	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
11	DEBARY	1-10	785	116	0.0	96.32	16.8	12,457	GAS	1,445	MCF	1.00	1,445	7,766	6.69
12	HIGGINS	1-4	129	0	0.0	91.61	0.0	0	GAS	0	MCF	0.00	0	0	0.00
13	HINES CC	1-4	2,204	1,044,332	63.7	95.24	22.3	7,048	GAS	7,360,219	MCF	1.00	7,360,219	39,582,565	3.79
14	INT CITY	1-14	1,186	2,154	0.2	95.60	7.6	12,451	GAS	26,816	MCF	1.00	26,816	144,209	6.70
15	OSPREY CC	1	505	39,325	10.5	96.13	58.1	7,647	GAS	300,700	MCF	1.00	300,700	1,617,137	4.11
16	SUWANNEE STEAM	1	67	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
17	SUWANNEE STEAM	2	66	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
18	SUWANNEE STEAM	3	67	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
19	SUWANNEE CT	1-3	200	27	0.0	99.14	0.0	12,500	GAS	335	MCF	1.00	335	1,801	6.72
20	TIGER BAY CC	1	225	7,719	4.6	89.68	95.3	8,476	GAS	65,429	MCF	1.00	65,429	351,870	4.56
21	UNIV OF FLA. CC	1	47	34,675	99.2	97.10	102.2	9,428	GAS	326,912	MCF	1.00	326,912	1,758,101	5.07
22	AVON PARK	1-2	69	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
23	BARTOW	1-4	228	0	0.0	81.13	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
24	BAYBORO	1-4	231	0	0.0	95.97	0.0	0	LIGHT OIL	0	BBLS	0.00	0	96	0.00
25	DEBARY	1-10	785	16	0.0	96.32	0.0	14,088	LIGHT OIL	39	BBLS	5.74	224	6,537	41.11
26	HIGGINS	1-4	129	0	0.0	91.61	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
27	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
28	INT CITY	1-14	1,186	6	0.2	95.60	0.0	17,500	LIGHT OIL	18	BBLS	5.83	105	6,136	102.27
29	RIO PINAR	1	16	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
30	SUWANNEE	1-3	200	5	0.0	99.14	0.0	14,528	LIGHT OIL	13	BBLS	5.92	77	2,074	39.13
31	TURNER	1-4	199	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
32	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	2,332	BBLS	5.83	13,585	341,226	0.00
33	SOLAR		19	2,644	18.7	0.00	0.0	0	SOLAR	0	N/A		0	0	0.00
34	TOTAL			2,873,853									23,616,417	103,562,549	3.60

Duke Energy Florida
Inventory Analysis
Estimated for the Period of : January through December 2017

	HEAVY OIL		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Subtotal
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	
11	UNIT COST	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	
12	AMOUNT	$	0	0	0	0	0	0	
	LIGHT OIL								
13	PURCHASES:								
14	UNITS	BBL	2,185	2,079	1,305	2,422	2,576	1,948	12,515
15	UNIT COST	$/BBL	153.97	159.28	216.81	146.23	141.69	167.18	159.43
16	AMOUNT	$	336,416	331,140	282,943	354,161	364,984	325,659	1,995,303
17	BURNED:								
18	UNITS	BBL	2,185	2,079	1,305	2,422	2,576	1,948	12,515
19	UNIT COST	$/BBL	153.97	159.28	216.81	146.23	141.69	167.18	159.43
20	AMOUNT	$	336,416	331,140	282,943	354,161	364,984	325,659	1,995,303
21	ENDING INVENTORY:								
22	UNITS	BBL	947,635	947,635	947,635	947,635	947,635	947,635	
23	UNIT COST	$/BBL	109.83	109.83	109.83	109.83	109.83	109.83	
24	AMOUNT	$	104,075,698	104,075,698	104,075,698	104,075,698	104,075,698	104,075,698	
	COAL								
25	PURCHASES:								
26	UNITS	TON	400,765	353,830	395,102	308,636	426,658	437,356	2,322,347
27	UNIT COST	$/TON	70.47	69.09	66.90	65.92	67.81	67.17	67.94
28	AMOUNT	$	28,240,918	24,446,219	26,430,916	20,346,221	28,929,952	29,375,644	157,769,870
29	BURNED:								
30	UNITS	TON	400,765	353,830	395,102	308,636	426,658	437,356	2,322,347
31	UNIT COST	$/TON	70.47	69.09	66.90	65.92	67.81	67.17	67.94
32	AMOUNT	$	28,240,918	24,446,219	26,430,916	20,346,221	28,929,952	29,375,644	157,769,870
33	ENDING INVENTORY:								
34	UNITS	TON	882,732	882,732	882,732	882,732	882,732	882,732	
35	UNIT COST	$/TON	70.47	69.09	66.90	65.92	67.81	67.17	
36	AMOUNT	$	62,203,917	60,988,219	59,051,593	58,192,342	59,854,526	59,289,931	
	GAS								
37	BURNED:								
38	UNITS	MCF	15,055,796	12,672,432	13,267,285	15,402,715	18,151,858	19,691,160	94,241,246
39	UNIT COST	$/MCF	4.51	4.55	4.61	4.20	4.30	4.14	4.36
40	AMOUNT	$	67,891,579	57,688,718	61,158,169	64,674,934	77,996,857	81,448,650	410,858,907
	NUCLEAR								
41	BURNED:								
42	UNITS	MMBTU	0	0	0	0	0	0	0
43	UNIT COST	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	AMOUNT	$	0	0	0	0	0	0	0

Duke Energy Florida
Inventory Analysis
Estimated for the Period of : January through December 2017

	HEAVY OIL		Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
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	
11	UNIT COST	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	
12	AMOUNT	$	0	0	0	0	0	0	
	LIGHT OIL								
13	PURCHASES:								
14	UNITS	BBL	1,394	2,581	2,630	1,061	2,839	2,402	25,422
15	UNIT COST	$/BBL	208.30	142.78	141.74	254.46	136.05	148.24	158.89
16	AMOUNT	$	290,364	368,505	372,783	269,987	386,250	356,069	4,039,261
17	BURNED:								
18	UNITS	BBL	1,394	2,581	2,630	1,061	2,839	2,402	25,422
19	UNIT COST	$/BBL	208.30	142.78	141.74	254.46	136.05	148.24	158.89
20	AMOUNT	$	290,364	368,505	372,783	269,987	386,250	356,069	4,039,261
21	ENDING INVENTORY:								
22	UNITS	BBL	947,635	947,635	947,635	947,635	947,635	947,635	
23	UNIT COST	$/BBL	109.83	109.83	109.83	109.83	109.83	109.83	
24	AMOUNT	$	104,075,698	104,075,698	104,075,698	104,075,698	104,075,698	104,075,698	
	COAL								
25	PURCHASES:								
26	UNITS	TON	480,852	475,901	444,791	299,087	294,557	390,226	4,707,761
27	UNIT COST	$/TON	66.46	66.01	65.54	62.58	61.51	60.80	66.03
28	AMOUNT	$	31,955,839	31,416,565	29,149,530	18,718,186	18,119,265	23,724,082	310,853,337
29	BURNED:								
30	UNITS	TON	480,852	475,901	444,791	299,087	294,557	390,226	4,707,761
31	UNIT COST	$/TON	66.46	66.01	65.54	62.58	61.51	60.80	66.03
32	AMOUNT	$	31,955,839	31,416,565	29,149,530	18,718,186	18,119,265	23,724,082	310,853,337
33	ENDING INVENTORY:								
34	UNITS	TON	882,732	882,732	882,732	882,732	882,732	882,732	
35	UNIT COST	$/TON	66.46	66.01	65.54	62.58	61.51	60.80	
36	AMOUNT	$	58,663,456	58,273,465	57,850,106	55,245,253	54,300,023	53,666,310	
	GAS								
37	BURNED:								
38	UNITS	MCF	20,336,850	20,743,588	19,200,406	18,089,452	14,492,163	14,779,435	201,883,140
39	UNIT COST	$/MCF	4.13	4.12	4.23	4.92	5.33	5.38	4.49
40	AMOUNT	$	83,894,763	85,369,629	81,228,339	88,912,548	77,199,356	79,482,398	906,945,940
	NUCLEAR								
41	BURNED:								
42	UNITS	MMBTU	0	0	0	0	0	0	0
43	UNIT COST	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	AMOUNT	$	0	0	0	0	0	0	0

Duke Energy Florida
Fuel Cost of Power Sold
Estimated for the Period of : January through December 2017

(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-17	ECONSALE	--	9,639		9,639	3.050	3.792	293,948	365,499	71,551
	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	--	62,957		62,957	2.545	2.545	1,602,253	1,602,253	0
	TOTAL		72,596		72,596	2.612	2.711	1,896,201	1,967,752	71,551
Feb-17	ECONSALE	--	7,068		7,068	2.734	3.400	193,248	240,286	47,038
	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	--	39,326		39,326	2.691	2.691	1,058,435	1,058,435	0
	TOTAL		46,394		46,394	2.698	2.799	1,251,683	1,298,721	47,038
Mar-17	ECONSALE	--	6,996		6,996	2.775	3.450	194,137	241,393	47,256
	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	--	70,645		70,645	2.538	2.538	1,793,288	1,793,288	0
	TOTAL		77,641		77,641	2.560	2.621	1,987,425	2,034,681	47,256
Apr-17	ECONSALE	--	9,610		9,610	3.392	4.218	325,957	405,297	79,340
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	84,368		84,368	2.392	2.392	2,017,970	2,017,970	0
	TOTAL		93,978		93,978	2.494	2.579	2,343,927	2,423,267	79,340
May-17	ECONSALE	--	7,349		7,349	3.329	4.140	244,693	304,253	59,560
	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	--	98,936		98,936	2.403	2.403	2,377,019	2,377,019	0
	TOTAL		106,285		106,285	2.467	2.523	2,621,712	2,681,272	59,560
Jun-17	ECONSALE	--	6,012		6,012	3.478	4.324	209,097	259,993	50,896
	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	--	101,407		101,407	2.413	2.413	2,446,981	2,446,981	0
	TOTAL		107,419		107,419	2.473	2.520	2,656,078	2,706,974	50,896

Duke Energy Florida
Fuel Cost of Power Sold
Estimated for the Period of : January through December 2017

(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-17	ECONSALE	--	3,548		3,548	3.233	4.020	114,697	142,616	27,919
	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	--	109,738		109,738	2.446	2.446	2,684,330	2,684,330	0
	TOTAL		113,286		113,286	2.471	2.495	2,799,027	2,826,946	27,919
Aug-17	ECONSALE	--	5,586		5,586	3.407	4.237	190,326	236,653	46,327
	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	--	109,823		109,823	2.462	2.462	2,703,432	2,703,432	0
	TOTAL		115,409		115,409	2.507	2.548	2,893,758	2,940,085	46,327
Sep-17	ECONSALE	--	2,645		2,645	3.085	3.836	81,602	101,466	19,864
	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	--	95,576		95,576	2.443	2.443	2,335,392	2,335,392	0
	TOTAL		98,221		98,221	2.461	2.481	2,416,994	2,436,858	19,864
Oct-17	ECONSALE	--	2,531		2,531	3.224	4.009	81,590	101,450	19,860
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	78,036		78,036	2.524	2.524	1,969,320	1,969,320	0
	TOTAL		80,567		80,567	2.546	2.570	2,050,910	2,070,770	19,860
Nov-17	ECONSALE	--	15,739		15,739	2.752	3.422	433,168	538,604	105,436
	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	--	45,057		45,057	2.684	2.684	1,209,264	1,209,264	0
	TOTAL		60,796		60,796	2.702	2.875	1,642,432	1,747,868	105,436
Dec-17	ECONSALE	--	5,981		5,981	2.572	3.198	153,818	191,259	37,441
	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	--	60,437		60,437	2.659	2.659	1,607,290	1,607,290	0
	TOTAL		66,418		66,418	2.652	2.708	1,761,108	1,798,549	37,441
Jan-17	ECONSALE	--	82,705		82,705	3.042	3.783	2,516,281	3,128,769	612,488
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-17	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	956,306		956,306	2.489	2.489	23,804,974	23,804,974	0
	TOTAL		1,039,011		1,039,011	2.533	2.592	26,321,255	26,933,743	612,488

Duke Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January through December 2017

(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-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	3,250			3,250	6.385	6.385	207,496
	SOCO Franklin	--	22,567			22,567	5.272	5.272	1,189,828
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	10,833			10,833	5.214	5.214	564,856
	TOTAL		36,650	0	0	36,650	5.354	5.354	1,962,180
Feb-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	275			275	6.995	6.995	19,251
	SOCO Franklin	--	15,271			15,271	6.190	6.190	945,243
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	1,723			1,723	6.261	6.261	107,876
	TOTAL		17,269	0	0	17,269	6.210	6.210	1,072,370
Mar-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	5,972			5,972	5.643	5.643	336,996
	SOCO Franklin	--	63,890			63,890	4.010	4.010	2,562,276
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	19,339			19,339	5.645	5.645	1,091,658
	TOTAL		89,202	0	0	89,202	4.474	4.474	3,990,930
Apr-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	8,574			8,574	4.815	4.815	412,846
	SOCO Franklin	--	75,078			75,078	3.539	3.539	2,657,010
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	34,203			34,203	5.346	5.346	1,828,375
	TOTAL		117,854	0	0	117,854	4.156	4.156	4,898,231
May-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	5,807			5,807	5.091	5.091	295,658
	SOCO Franklin	--	110,677			110,677	3.463	3.463	3,832,747
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	28,564			28,564	5.562	5.562	1,588,833
	TOTAL		145,048	0	0	145,048	3.942	3.942	5,717,238
Jun-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	14,566			14,566	5.028	5.028	732,425
	SOCO Franklin	--	153,256			153,256	3.333	3.333	5,107,530
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	59,554			59,554	5.339	5.339	3,179,402
	TOTAL		227,376	0	0	227,376	3.967	3.967	9,019,357
Jan-17	OTHER	--	0			0	0.000	0.000	0
THRU	Osprey (Calpine)	--	0			0	0.000	0.000	0
Jun-17	SHADY HILLS	--	38,445			38,445	5.214	5.214	2,004,672
	SOCO Franklin	--	440,739			440,739	3.697	3.697	16,294,634
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	154,216			154,216	5.422	5.422	8,361,000
	TOTAL		633,399	0	0	633,399	4.209	4.209	26,660,306

Duke Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January through December 2017

(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)
Jul-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	26,823			26,823	5.039	5.039	1,351,492
	SOCO Franklin	--	182,143			182,143	3.279	3.279	5,972,971
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	77,831			77,831	5.295	5.295	4,121,445
	TOTAL		286,797	0	0	286,797	3.991	3.991	11,445,908
Aug-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	30,474			30,474	5.013	5.013	1,527,661
	SOCO Franklin	--	187,079			187,079	3.273	3.273	6,122,439
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	92,746			92,746	5.290	5.290	4,906,438
	TOTAL		310,298	0	0	310,298	4.047	4.047	12,556,538
Sep-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	19,345			19,345	4.883	4.883	944,592
	SOCO Franklin	--	160,930			160,930	3.340	3.340	5,375,414
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	55,730			55,730	5.449	5.449	3,036,705
	TOTAL		236,004	0	0	236,004	3.965	3.965	9,356,711
Oct-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	19,526			19,526	5.701	5.701	1,113,093
	SOCO Franklin	--	160,577			160,577	3.318	3.318	5,327,370
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	57,109			57,109	6.214	6.214	3,548,867
	TOTAL		237,212	0	0	237,212	4.211	4.211	9,989,330
Nov-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	3,633			3,633	6.430	6.430	233,555
	SOCO Franklin	--	6,098			6,098	10.546	10.546	643,100
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	24,743			24,743	6.475	6.475	1,602,082
	TOTAL		34,474	0	0	34,474	7.190	7.190	2,478,737
Dec-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	1,026			1,026	6.337	6.337	65,034
	SOCO Franklin	--	19,281			19,281	5.737	5.737	1,106,131
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	2,202			2,202	6.932	6.932	152,631
	TOTAL		22,509	0	0	22,509	5.881	5.881	1,323,796
Jan-17	OTHER	--	0			0	0.000	0.000	0
THRU	Osprey (Calpine)	--	0			0	0.000	0.000	0
Dec-17	SHADY HILLS	--	139,270			139,270	5.199	5.199	7,240,099
	SOCO Franklin	--	1,156,847			1,156,847	3.530	3.530	40,842,059
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	464,577			464,577	5.538	5.538	25,729,168
			1,760,693	0	0	1,760,693	4.192	4.192	73,811,326
TOTAL									

Duke Energy Florida
Energy Payments to Qualifying Facilities
Estimated for the Period of : January through December 2017

(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) ENERGY COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(A)
Jan-17	QUAL. FACILITIES	COGEN	296,006			296,006	4.114	12.213	12,177,556
Feb-17	QUAL. FACILITIES	COGEN	267,366			267,366	4.126	13.093	11,032,109
Mar-17	QUAL. FACILITIES	COGEN	270,166			270,166	4.376	13.250	11,823,009
Apr-17	QUAL. FACILITIES	COGEN	267,704			267,704	4.195	13.150	11,229,874
May-17	QUAL. FACILITIES	COGEN	286,889			286,889	4.206	12.563	12,066,147
Jun-17	QUAL. FACILITIES	COGEN	277,669			277,669	4.230	12.864	11,745,616
Jul-17	QUAL. FACILITIES	COGEN	286,942			286,942	4.252	12.607	12,199,522
Aug-17	QUAL. FACILITIES	COGEN	286,908			286,908	4.279	12.635	12,276,250
Sep-17	QUAL. FACILITIES	COGEN	277,650			277,650	4.282	12.917	11,889,369
Oct-17	QUAL. FACILITIES	COGEN	239,983			239,983	4.291	14.281	10,297,653
Nov-17	QUAL. FACILITIES	COGEN	276,511			276,511	4.141	12.811	11,450,142
Dec-17	QUAL. FACILITIES	COGEN	296,037			296,037	4.192	12.290	12,408,768
TOTAL	QUAL. FACILITIES	COGEN	3,329,832			3,329,832	4.222	12.862	140,596,014

Duke Energy Florida
Economy Energy Purchases
Estimated for the Period of : January through December 2017

(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-17	ECONPURCH	--	3,844	4.075	4.075	156,642	4.564	175,440	18,798
	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	-
	TOTAL		7,241	4.274	4.274	309,512	4.534	328,310	18,798
Feb-17	ECONPURCH	--	2,903	4.288	4.288	124,491	4.803	139,429	14,938
	SEPA	--	3,068	4.500	4.500	138,076	4.500	138,076	-
	TOTAL		5,971	4.397	4.397	262,567	4.647	277,505	14,938
Mar-17	ECONPURCH	--	7,273	4.058	4.058	295,167	4.545	330,587	35,420
	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	-
	TOTAL		10,670	4.199	4.199	448,037	4.531	483,457	35,420
Apr-17	ECONPURCH	--	4,308	4.580	4.580	197,301	5.130	220,977	23,676
	SEPA	--	3,288	4.500	4.500	147,938	4.500	147,938	-
	TOTAL		7,595	4.545	4.545	345,239	4.857	368,915	23,676
May-17	ECONPURCH	--	3,368	4.965	4.965	167,248	5.561	187,318	20,070
	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	-
	TOTAL		6,766	4.732	4.732	320,118	5.028	340,188	20,070
Jun-17	ECONPURCH	--	3,145	5.104	5.104	160,512	5.717	179,779	19,267
	SEPA	--	3,288	4.500	4.500	147,938	4.500	147,938	-
	TOTAL		6,432	4.795	4.795	308,450	5.095	327,717	19,267
Jan-17 THRU Jun-17	ECONPURCH	--	24,841	4.434	4.434	1,101,361	4.97	1,233,530	132,169
	SEPA	--	19,835	4.500	4.500	892,562	4.50	892,562	-
	TOTAL		44,676	4.463	4.463	1,993,923	4.759	2,126,092	132,169

Duke Energy Florida
Economy Energy Purchases
Estimated for the Period of : January through December 2017

(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-17	ECONPURCH	--	5,863	5.011	5.011	293,762	5.612	329,008	35,246
	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	-
	TOTAL		9,260	4.823	4.823	446,632	5.204	481,878	35,246
Aug-17	ECONPURCH	--	4,880	5.382	5.382	262,674	6.028	294,196	31,522
	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	-
	TOTAL		8,277	5.020	5.020	415,544	5.401	447,066	31,522
Sep-17	ECONPURCH	--	3,678	4.888	4.888	179,803	5.475	201,385	21,582
	SEPA	--	3,288	4.500	4.500	147,938	4.500	147,938	-
	TOTAL		6,966	4.705	4.705	327,741	5.015	349,323	21,582
Oct-17	ECONPURCH	--	9,939	4.575	4.575	454,696	5.124	509,270	54,574
	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	-
	TOTAL		13,336	4.556	4.556	607,566	4.965	662,140	54,574
Nov-17	ECONPURCH	--	5,010	4.135	4.135	207,190	4.632	232,057	24,867
	SEPA	--	3,288	4.500	4.500	147,938	4.500	147,938	-
	TOTAL		8,298	4.280	4.280	355,128	4.580	379,995	24,867
Dec-17	ECONPURCH	--	3,065	3.859	3.859	118,245	4.321	132,430	14,185
	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	-
	TOTAL		6,462	4.196	4.196	271,115	4.415	285,300	14,185
Jan-17 THRU Dec-17	ECONPURCH	--	57,276	4.570	4.570	2,617,731	5.119	2,931,876	314,145
	SEPA	--	39,998	4.500	4.500	1,799,918	4.500	1,799,918	-
	TOTAL		97,274	4.541	4.541	4,417,649	4.864	4,731,794	314,145

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Residential Bill Comparison
Estimated for the Period of : January 2017 *

	Current Nov-2016 * ($/1000 KWH)	Requested Jan-2017 * ($/1000 KWH)	Difference from Current $	Difference from Current %
Base Rate *	$58.99	$58.99	$0.00	0.00%
Fuel Cost Recovery	26.79	33.77	6.98	26.05%
Capacity Cost Recovery (CCR)	13.47	11.38	(2.09)	-15.52%
Energy Conservation Cost Recovery (ECCR)	3.25	3.17	(0.08)	-2.46%
Environmental Cost Recovery (ECRC)	1.84	1.51	(0.33)	-17.93%
Nuclear CR3 Uprate	1.76	1.56	(0.20)	-11.36%
Nuclear Levy	0.00	0.00	0.00	0.00%
Securitization	2.87	2.87	0.00	0.00%
Subtotal	108.97	113.25	4.28	3.93%
Gross Receipts Tax	2.79	2.90	0.11	3.94%
Total	$111.76	$116.15	$4.39	3.93%

* Nov-2016 Base Rate includes the $0.49 GBRA adjustment approved by the Commission at the August 9, 2016 Agenda. The Requested Jan-2017 does not include the GBRA Adjustment in DEF's petition filed in Docket 160178-EI. This adjustment, which includes the Osprey Combined Cycle Acquisition and Phase 2 of the Hines Chiller Uprate Project, will take effect with the February 2017 billing cycle. DEF has requested a GBRA adjustment of $1.50 on a 1,000kWh

Calculation of Inverted Residential Fuel Rates

	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	14,292,966	3.667	$ 524,123,082	3.377	$ 482,624,335
Over 1,000 kWh	5,847,726	3.667	214,436,105	4.377	255,934,852
Total	20,140,692		$ 738,559,187		$ 738,559,187
Rate Differential by Tier - Cents per kWh				1.000	

Residential Sales:	
Total	20,141,254
Time of Use	562
Levelized	20,140,692

Docket No. 160001-EI
Schedule H1
Exhibit CAM-3, Part 2

Duke Energy Florida
Generating System Comparative Data by Fuel Type

		2014 Actual	2015 Actual	2016 Actual / Estimated	2017 Projection	2015 vs. 2014	2016 vs. 2015	2017 vs. 2016
FUEL COST OF SYSTEM NET GENERATION ($)								
HEAVY OIL		0	0	0	0	0.0%	0.0%	0.0%
LIGHT OIL		21,114,159	20,687,452	11,112,027	4,039,261	-2.0%	-46.3%	-63.6%
COAL		479,549,089	379,954,861	314,437,587	310,853,337	-20.8%	-17.2%	-1.1%
GAS		1,053,354,312	947,933,972	806,113,993	906,945,940	-10.0%	-15.0%	12.5%
NUCLEAR		0	0	0	0	0.0%	0.0%	0.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	$	1,554,017,561	1,348,576,284	1,131,663,607	1,221,838,538	-13.2%	-16.1%	8.0%
SYSTEM NET GENERATION (MWH)								
HEAVY OIL		123,377	0	0	0	-100.0%	0.0%	0.0%
LIGHT OIL		35,150	72,848	37,730	529	107.2%	-48.2%	-98.6%
COAL		10,633,975	9,718,456	8,784,950	10,286,213	-8.6%	-9.6%	17.1%
GAS		23,066,236	25,227,323	24,915,809	26,700,833	9.4%	-1.2%	7.2%
NUCLEAR		0	0	0	0	0.0%	0.0%	0.0%
SOLAR		0	0	8,783	32,556	0.0%	0.0%	270.7%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	MWH	33,858,739	35,018,627	33,747,272	37,020,131	3.4%	-3.6%	9.7%
UNITS OF FUEL BURNED								
HEAVY OIL	BBL	250,994	0	0	0	-100.0%	0.0%	0.0%
LIGHT OIL	BBL	132,000	162,382	92,642	25,422	23.0%	-42.9%	-72.6%
COAL	TON	4,792,094	4,425,252	4,125,705	4,707,761	-7.7%	-6.8%	14.1%
GAS	MCF	177,503,510	198,464,799	195,915,062	201,883,140	11.8%	-1.3%	3.0%
NUCLEAR	MMBTU	0	0	0	0	0.0%	0.0%	0.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
BTUS BURNED (MMBTU)								
HEAVY OIL		1,529,500	0	0	0	-100.0%	0.0%	0.0%
LIGHT OIL		764,007	927,656	534,331	148,078	21.4%	-42.4%	-72.3%
COAL		111,597,504	102,196,707	93,826,406	106,890,768	-8.4%	-8.2%	13.9%
GAS		180,039,881	203,148,563	197,955,707	201,883,140	12.8%	-2.6%	2.0%
NUCLEAR		0	0	0	0	0.0%	0.0%	0.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	MMBTU	293,930,892	306,272,926	292,316,445	308,921,986	4.2%	-4.6%	5.7%
GENERATION MIX (% MWH)								
HEAVY OIL		0.36%	0.00%	0.00%	0.00%	-109.9%	0.0%	0.0%
LIGHT OIL		0.10%	0.21%	0.11%	0.00%	96.2%	-48.1%	-89.3%
COAL		31.41%	27.75%	26.03%	27.79%	-11.8%	-6.1%	6.9%
GAS		68.13%	72.04%	73.83%	72.13%	5.7%	2.5%	-2.3%
NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.0%	0.0%	0.0%
SOLAR		0.00%	0.00%	0.03%	0.09%	0.0%	0.0%	384.6%
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								
HEAVY OIL	$/BBL	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
LIGHT OIL	$/BBL	159.96	127.40	119.95	158.89	-20.4%	-5.9%	32.5%
COAL	$/TON	100.07	85.86	76.21	66.03	-14.2%	-11.2%	-13.4%
GAS	$/MCF	5.93	4.78	4.11	4.49	-19.5%	-13.9%	9.2%
NUCLEAR	$/MMBTU	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
FUEL COST PER MMBTU ($/MMBTU)								
HEAVY OIL		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
LIGHT OIL		27.64	22.30	20.80	27.28	-19.3%	-6.7%	31.2%
COAL		4.30	3.72	3.35	2.91	-13.5%	-9.9%	-13.2%
GAS		5.85	4.67	4.07	4.49	-20.3%	-12.7%	10.3%
NUCLEAR		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
TOTAL	$/MMBTU	5.29	4.40	3.87	3.96	-16.7%	-12.1%	2.2%
BTU BURNED PER KWH (BTU/KWH)								
HEAVY OIL		12,397	0	0	0	-100.0%	0.0%	0.0%
LIGHT OIL		21,735	12,734	14,162	280,079	-41.4%	11.2%	1877.7%
COAL		10,494	10,516	10,680	10,392	0.2%	1.6%	-2.7%
GAS		7,805	8,053	7,945	7,561	3.2%	-1.3%	-4.8%
NUCLEAR		0	0	0	0	0.0%	0.0%	0.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	BTU/KWH	8,681	8,746	8,662	8,345	0.7%	-1.0%	-3.7%
GENERATED FUEL COST PER KWH (C/KWH)								
HEAVY OIL		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
LIGHT OIL		60.07	28.40	29.45	764.00	-52.7%	3.7%	2494.1%
COAL		4.51	3.91	3.58	3.02	-13.3%	-8.4%	-15.6%
GAS		4.57	3.76	3.24	3.40	-17.7%	-13.9%	5.0%
NUCLEAR		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
TOTAL	C/KWH	4.59	3.85	3.35	3.30	-16.1%	-12.9%	-1.6%

Docket 160001-EI
Exhibit No. ____(CAM-3)
Part 3

DUKE ENERGY FLORIDA

FUEL AND CAPACITY COST RECOVERY FACTOR

JANUARY THROUGH DECEMBER 2017

PART 3 – 2017 CAPACITY COST RECOVERY SCHEDULES

Schedule E12-A – Calculation of Projected Capacity Costs

Schedule E12-B – Calculation of Estimated/Actual 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
Calculation Projected Capacity Costs
For the Year 2017

Docket No. 160001-EI
Exhibit__CAM-3, Part 3
Schedule E12-A
Page 1 of 2

		EST Jan-17	EST Feb-17	EST Mar-17	EST Apr-17	EST May-17	EST Jun-17	EST Jul-17	EST Aug-17	EST Sep-17	EST Oct-17	EST Nov-17	EST Dec-17	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	60,858,768
3	Orlando Cogen Limited (ORLACOGL)	5,102,803	5,102,803	5,102,803	5,102,803	5,102,803	5,102,803	5,102,803	5,102,803	5,102,803	5,102,803	5,102,803	5,102,803	61,233,636
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)	6,965,674	6,965,674	6,965,674	6,965,674	6,965,674	6,965,674	6,965,674	6,965,674	6,965,674	6,965,674	6,965,674	6,965,674	83,588,088
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	9,611,352
8	Subtotal - Base Level Capacity Costs	23,974,387	23,974,387	23,974,387	23,974,387	23,974,387	23,974,387	23,974,387	23,974,387	23,974,387	23,974,387	23,974,387	23,974,387	287,692,644
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	22,268,609	22,268,608	22,268,608	22,268,608	22,268,608	22,268,609	22,268,609	22,268,609	22,268,609	22,268,609	22,268,609	22,268,609	267,223,307
11	**Intermediate Production Level Capacity Costs**													
12	Southern Franklin	4,565,768	4,565,768	2,682,208	2,682,208	2,951,288	5,158,612	6,250,556	6,250,556	4,612,640	2,701,738	2,701,738	3,520,696	48,643,776
13	Schedule H Capacity Sales - NSB	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Subtotal - Intermediate Level Capacity Costs	4,565,768	4,565,768	2,682,208	2,682,208	2,951,288	5,158,612	6,250,556	6,250,556	4,612,640	2,701,738	2,701,738	3,520,696	48,643,776
15	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%	
16	Intermediate Level Jurisdict. Capacity Costs	3,319,450	3,319,450	1,950,046	1,950,046	2,145,676	3,750,466	4,544,342	4,544,342	3,353,528	1,964,245	1,964,245	2,559,652	35,365,485
17	**Peaking Production Level Capacity Costs**													
18	Shady Hills	1,970,868	1,970,868	1,407,765	1,365,741	1,912,038	3,887,109	3,887,109	3,887,109	1,813,983	1,365,741	1,365,741	1,970,868	26,804,940
19	Vandolah (NSG)	2,777,276	2,792,868	2,001,752	1,979,480	2,699,316	5,565,668	5,548,960	5,504,412	2,634,348	1,940,500	1,985,048	2,792,868	38,222,496
20	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Subtotal - Peaking Level Capacity Costs	4,748,144	4,763,736	3,409,517	3,345,221	4,611,354	9,452,777	9,436,069	9,391,521	4,448,331	3,306,241	3,350,789	4,763,736	65,027,436
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	4,554,610	4,569,566	3,270,545	3,208,870	4,423,395	9,067,482	9,051,455	9,008,723	4,267,017	3,171,479	3,214,211	4,569,566	62,376,918
24	**Other Capacity Costs**													
25	Retail Wheeling	(16,864)	(12,365)	(12,240)	(16,811)	(12,857)	(10,518)	(6,207)	(9,772)	(4,627)	(4,427)	(27,535)	(10,464)	(144,689)
26	RRSSA Second Amendment [1]													
27	Batch-19 Nuclear Fuel [2]													
28	Total Other Capacity Costs													
29														
30	**Total Capacity Costs (line 10+16+23+28)**	31,918,164	31,933,653	29,261,390	29,191,180	30,601,326	36,848,579	37,626,777	37,576,516	31,645,178	29,156,593	29,172,254	31,079,186	386,010,796
31	Estimated/Actual True-Up Provision - Jan - Dec 2016													(14,665,234)
32	**Total Capacity Costs w/ True-Up**													371,345,562
33	Revenue Tax Multiplier													1.00072
34	**Total Recoverable Capacity Costs**													371,612,930
35	**Nuclear Cost Recovery Clause**													51,700,333
36	Revenue Tax Multiplier													1.00072
37	**Total Recoverable Nuclear Costs**													51,737,557
38	**ISFSI Revenue Requirement**													5,283,567
39	Revenue Tax Multiplier													1.00072
40	**Total Recoverable Nuclear Costs**													5,287,371
41	**Total Recov Capacity & Nuclear Costs (line 34+37+40)**													428,637,858

[1] Approved in Commission Order No. PSC-16-0138-FOF-EI
[2] Approved in Commission Order No. PSC-15-0465-S-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	74.00
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	Dec-23	QF	Purch	39.60
7	Florida Power Development	May-14	May-34	QF	Purch	60.00
8	Southern - Franklin	Jun-16	May-21	Other	Purch	425.00
9	Schedule H Capacity - New Smyrna Beach	Nov-85	see note (1)	Other	Sale	1.00
10	Chattahoochee	Jan-03	Dec-17	Other	Purch	5.25
11	Vandolah (NSG)	Jun-12	May-27	Other	Puch	655.00
12	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 DEF or NSB upon 1 year's written notice.

Duke Energy Florida
Calculation of Estimated/Actual True-up
For the Year 2016

Docket No. 160001-EI
Exhibit__CAM-3, Part 3
Schedule E12-B

		ACT Jan-16	ACT Feb-16	ACT Mar-16	ACT Apr-16	ACT May-16	ACT Jun-16	EST Jul-16	EST Aug-16	EST Sep-16	EST Oct-16	EST Nov-16	EST Dec-16	TOTAL
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	3,266,545	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	56,354,954
3	Orlando Cogen Limited (ORLACOGL)	13,409,604	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	66,804,417
4	Pasco County Resource Recovery (PASCOUNT)	1,577,570	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	20,033,920
5	Pinellas County Resource Recovery (PINCOUNT)	3,755,303	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	47,689,443
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	6,306,018	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	79,211,169
7	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	603,090	584,735	575,947	555,284	532,520	498,053	800,946	800,946	800,946	800,946	800,946	800,946	8,155,306
8	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Southern - Scherer	2,149,228	1,826,729	1,773,417	1,774,164	1,775,120	276,573	-	-	-	-	-	-	9,575,232
10	Calpine Osprey													
11	Subtotal - Base Level Capacity Costs													
12	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%	
13	Base Level Jurisdictional Capacity Costs													
14	**Intermediate Production Level Capacity Costs**													
15	Southern - Franklin	3,201,566	3,298,621	3,206,417	3,469,625	3,102,253	5,095,516	3,977,920	3,977,920	3,977,920	3,977,920	3,977,920	3,977,920	45,241,518
16	Schedule H Capacity Sales - NSB	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Subtotal - Intermediate Level Capacity Costs	3,201,566	3,298,621	3,206,417	3,469,625	3,102,253	5,095,516	3,977,920	3,977,920	3,977,920	3,977,920	3,977,920	3,977,920	45,241,518
19	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%	
20	Intermediate Level Jurisdictional Capacity Costs	2,327,635	2,398,196	2,331,161	2,522,522	2,255,431	3,704,593	2,892,067	2,892,067	2,892,067	2,892,067	2,892,067	2,892,067	32,891,940
21	**Peaking Production Level Capacity Costs**													
22	Chattahoochee	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Vandolah (RRI)	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Shady Hills Power Company LLC	1,410,667	1,671,610	1,406,700	1,366,200	1,886,760	3,855,600	3,887,109	3,887,109	1,813,983	1,365,741	1,365,741	1,970,868	25,888,088
25	Vandolah (NSG)	2,888,436	2,892,622	2,035,755	1,947,188	2,800,279	5,784,009	5,548,960	5,504,412	2,634,348	1,940,500	1,985,048	2,792,868	38,754,425
26	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Subtotal - Peaking Level Capacity Costs	4,299,103	4,564,232	3,442,455	3,313,388	4,687,039	9,639,609	9,436,069	9,391,521	4,448,331	3,306,241	3,350,789	4,763,736	64,642,513
28	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%	
29	Peaking Level Jurisdictional Capacity Costs	4,123,872	4,378,193	3,302,140	3,178,334	4,495,995	9,246,699	9,051,455	9,008,723	4,267,017	3,171,479	3,214,211	4,569,566	62,007,684
30	**Other Capacity Costs**													
31	Retail Wheeling	(33,737)	(1,790)	(6,527)	(149,519)	(1,545)	-	(10,552)	(9,520)	(3,987)	(3,672)	(13,683)	(6,532)	(241,063)
32	Batch 19 Nuclear Fuel													
33	Other Jurisdictional Capacity Costs													
34	**Subtotal Jurisd Capacity Costs (Line 13+20+29+33)**	36,845,611	31,001,440	29,795,934	29,701,997	30,880,285	35,657,755	34,628,864	34,587,164	29,850,991	28,755,768	28,788,489	30,092,937	380,587,235
35	**Nuclear Cost Recovery Clause Costs (net of tax)**													
36	Levy Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
37	CR3 Uprate Costs	4,861,279	4,833,013	4,804,746	4,776,479	4,748,212	4,719,946	4,691,679	4,663,412	4,635,145	4,606,878	4,578,612	4,550,345	56,469,745
38	**Total NCRC Costs - Order No. PSC-15-0586-FOF-EI**	4,861,279	4,833,013	4,804,746	4,776,479	4,748,212	4,719,946	4,691,679	4,663,412	4,635,145	4,606,878	4,578,612	4,550,345	56,469,745
39	**Total Jurisdictional Capacity Costs (Line 34+38)**	41,706,890	35,834,453	34,600,679	34,478,476	35,628,497	40,377,701	39,320,542	39,250,575	34,486,136	33,362,646	33,367,101	34,643,282	437,056,980
40	**Capacity Revenues**													
41	Capacity Cost Recovery Revenues (net of tax)	33,281,758	33,857,575	32,975,595	34,435,237	40,699,538	46,120,530	48,253,503	48,974,879	49,176,389	45,339,440	37,855,002	36,604,066	487,573,513
42	Prior Period True-Up Provision Over/(Under) Recovery	(3,220,271)	(3,220,271)	(3,220,271)	(2,900,148)	(2,900,139)	(2,900,139)	(2,900,139)	(2,900,139)	(2,900,139)	(2,900,139)	(2,900,139)	(2,900,135)	(35,762,070)
43	**Current Period Revenues (net of tax)**	30,061,487	30,637,304	29,755,324	31,535,089	37,799,399	43,220,391	45,353,364	46,074,740	46,276,250	42,439,301	34,954,863	33,703,931	451,811,442
44	**True-Up Provision**													
45	True-Up Provision - Over/(Under) Recov (Line 43-39)	(11,645,403)	(5,197,149)	(4,845,356)	(2,943,386)	2,170,902	2,842,690	6,032,821	6,824,164	11,790,113	9,076,655	1,587,762	(939,350)	14,754,463
46	Interest Provision for the Month	(13,312)	(15,364)	(16,922)	(15,793)	(13,154)	(12,389)	(4,367)	(2,860)	(584)	1,273	1,969	2,274	(89,229)
47	Current Cycle Balance - Over/(Under)	(11,658,715)	(16,871,228)	(21,733,506)	(24,692,684)	(22,534,936)	(19,704,635)	(13,676,181)	(6,854,877)	4,934,652	14,012,580	15,602,311	14,665,234	14,665,234
48	Prior Period Balance - Over/(Under) Recovered	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)
49	Prior Period Cumulative True-Up Collected/(Refunded)	3,220,271	6,440,543	9,660,814	12,560,962	15,461,101	18,361,240	21,261,379	24,161,518	27,061,657	29,961,796	32,861,935	35,762,070	35,762,070
50	Prior Period True-up Balance - Over/(Under)	(32,541,799)	(29,321,528)	(26,101,256)	(23,201,108)	(20,300,969)	(17,400,830)	(14,500,691)	(11,600,552)	(8,700,413)	(5,800,274)	(2,900,135)	(0)	(0)
51	**Net Capacity True-up Over/(Under) (Line 47+50)**	($44,200,514)	($46,192,755)	($47,834,762)	($47,893,792)	($42,835,905)	($37,105,465)	($28,176,872)	($18,455,429)	($3,765,761)	$8,212,306	$12,702,176	$14,665,234	$14,665,234

Duke Energy Florida
Calculation of Energy and Demand Percent by Rate Class
Using 12 CP & 1/13th AD Allocation Method for Production Demand
For the Year 2017

Docket No. 160001-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												**0.30%**
RS-1, RST-1, RSL-1, RSL-2, RSS-1												
Secondary	0.518	20,141,254	4,439.32	0.9467387	21,274,354	4,689.06	2,428.58	51.544%	61.523%	60.755%	1,115,172	3,335
General Service Non-Demand												
GS-1, GST-1												
Secondary	0.682	1,837,382	307.72	0.9467387	1,940,749	325.03	221.55	4.702%	4.265%	4.298%		
Primary	0.682	15,404	2.58	0.9762055	15,779	2.64	1.80	0.038%	0.035%	0.035%		
Transmission	0.682	3,081	0.52	0.9862055	3,124	0.52	0.36	0.008%	0.007%	0.007%		
								4.748%	4.306%	4.340%	100,920	302
General Service												
GS-2 Secondary	1.000	170,272	19.44	0.9467387	179,851	20.53	20.53	0.436%	0.269%	0.282%	3,539	11
General Service Demand												
GSD-1, GSDT-1												
Secondary	0.749	12,108,998	1,846.29	0.9467387	12,790,222	1,950.16	1,460.07	30.988%	25.587%	26.003%		
Transm Del/ Primary Mtr	0.749	3,326	0.51	0.9762055	3,407	0.52	0.39	0.008%	0.007%	0.007%		
Sec Del/Primary Mtr	0.749	46,857	7.14	0.9762055	47,999	7.32	5.48	0.116%	0.096%	0.098%		
Primary	0.749	2,302,950	351.14	0.9762055	2,359,083	359.70	269.30	5.716%	4.719%	4.796%		
SS-1 Primary	1.166	32,162	3.15	0.9762055	32,946	3.23	3.76	0.080%	0.042%	0.045%		
Transm Del/ Primary Mtr	1.166	2,282	0.22	0.9762055	2,338	0.23	0.27	0.006%	0.003%	0.003%		
Transmission	1.166	8,609	0.84	0.9862055	8,729	0.85	1.00	0.021%	0.011%	0.012%		
								36.935%	30.466%	30.963%	482,992	1,445
Curtailable												
CS-1, CST-1, CS-2, CST-2, SS-3												
Primary	1.305	81,904	7.16	0.9762055	83,900	7.34	9.58	0.203%	0.096%	0.105%		
SS-3 Primary	0.583	50,697	9.93	0.9762055	51,933	10.17	5.93	0.126%	0.133%	0.133%		
								0.329%	0.230%	0.237%	4,888	15
Interruptible												
IS-1, IST-1, IS-2, IST-2												
Secondary	1.009	87,039	9.84	0.9467387	91,936	10.40	10.49	0.223%	0.136%	0.143%		
Sec Del/Primary Mtr	1.009	4,421	0.50	0.9762055	4,529	0.51	0.52	0.011%	0.007%	0.007%		
Primary Del / Primary Mtr	1.009	1,321,165	149.41	0.9762055	1,353,368	153.05	154.49	3.279%	2.008%	2.106%		
Primary Del / Transm Mtr	1.009	425	0.05	0.9862055	431	0.05	0.05	0.001%	0.001%	0.001%		
Transm Del/ Primary Mtr	1.009	249,648	28.23	0.9762055	255,733	28.92	29.19	0.620%	0.379%	0.398%		
Transm Del/ Transm Mtr	1.009	268,068	30.32	0.9862055	271,818	30.74	31.03	0.659%	0.403%	0.423%		
SS-2 Primary	0.870	9,777	1.28	0.9762055	10,015	1.31	1.14	0.024%	0.017%	0.018%		
Transm Del/ Primary Mtr	0.870	72,672	9.54	0.9762055	74,443	9.77	8.50	0.180%	0.128%	0.132%		
Transmission	0.870	8,497	1.12	0.9862055	8,616	1.13	0.98	0.021%	0.015%	0.015%		
								5.017%	3.095%	3.243%	51,937	155
Lighting												
LS-1 (Secondary)	5.506	387,147	8.03	0.9467387	408,927	8.48	46.68	0.991%	0.111%	0.179%	8,442	25
Total		39,214,037	7,234.27		41,274,230	7,621.67	4,711.67	100.000%	100.000%	100.000%	1,767,890	5,287

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2015 (FPSC rule 25-6.0437 (7))
(2) Projected mWh sales for the period Jan-Dec 2017
(3) Calculated: Column 2 / (8,760 hours x Column 1)
(4) Based on system average line loss analysis for 2015
(5) Calculated: Column 2 / Column 4
(6) Calculated: Column 3 / Column 4
(7) Calculated: Column 5 / 8,760 hours
(8) Calculated: Column 7 / Total Column 7
(9) Calculated: Column 6 / Total Column 6
(10) Calculated: Column 8 x 1/13 + Column 9 x 12/13
(11) Projected Base Energy & Demand Revenues for Jan-Dec 2017
(12) Uniform Percent Calculated: Column 12 Total / Column 11 Total
Calculated: Column 11 x Uniform Percent

Duke Energy Florida
Calculation of Capacity Cost Recovery Factors by Rate Class
For the Year 2017

Docket No. 160001-EI
Exhibit__CAM-3, Part 3
Schedule E12-E
Page 1 of 2

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) Levy Production Demand Costs ($)	(6) CR3 Production Demand Costs ($)	(7) Capacity + Nuclear + ISFSI Production Demand Costs ($)	(8) Capacity CCR Factor (c/kWh)	(9) ISFSI CCR Factor (c/kWh)	(10) Levy CCR Factor (c/kWh)	(11) CR3 CCR Factor (c/kWh)	(12) Capacity & Nuclear CCR Factor (c/kWh)
Residential												
RS-1, RST-1, RSL-1, RSL-2, RSS-1												
Secondary	60.755%	20,141,254	$225,773,930	$3,335,234	$0	$31,433,222	$260,542,386	**1.121**	**0.017**	**0.000**	**0.156**	**1.294**
General Service Non-Demand												
GS-1, GST-1												
Secondary		1,837,382						**0.869**	**0.016**	**0.000**	**0.121**	**1.006**
Primary		15,250						**0.860**	**0.016**	**0.000**	**0.120**	**0.996**
Transmission		3,019						**0.852**	**0.016**	**0.000**	**0.119**	**0.986**
TOTAL GS	4.340%	1,855,651	16,128,410	301,829	0	2,245,467	18,675,706					
General Service												
GS-2 Secondary	0.282%	170,272	1,048,594	10,585	0	145,990	1,205,169	**0.616**	**0.006**	**0.000**	**0.086**	**0.708**
General Service Demand												
GSD-1, GSDT-1, SS-1												
Secondary		12,108,998										
Primary		2,363,701										
Transmission		8,437										
TOTAL GSD	30.963%	14,481,136	115,064,327	1,444,523	0	16,019,753	132,528,603					
Curtailable												
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3												
Secondary		-										
Primary		131,275										
Transmission		-										
TOTAL CS	0.237%	131,275	882,238	14,618	0	122,829	1,019,685					
Interruptible												
IS-1, IST-1, IS-2, IST-2, SS-2												
Secondary		87,039										
Primary		1,641,106										
Transmission		271,450										
TOTAL IS	3.243%	1,999,595	12,050,639	155,332	0	1,677,742	13,883,713					
Lighting												
LS-1 Secondary	0.179%	387,147	664,792	25,249	0	92,555	782,596	**0.172**	**0.007**	**0.000**	**0.024**	**0.203**
Total	100.000%	39,166,331	$371,612,930	$5,287,371	$0	$51,737,557	$428,637,858	**0.949**	**0.013**	**0.000**	**0.132**	**1.094**

Notes:

(1) From Schedule E12-D, Column 10
(2) Projected mWh sales at effective voltage level for Jan-Dec
(3) Column 1 x Total Recoverable Payments (Schedule E12-A)
(4) From Schedule E12-D, Column 12
(5) (Column 10 x Column 2) x 10
(6) Column 1 x Total Recoverable Payments (Schedule E12-A)
(7) Column 3 + Column 4 + Column 5 + Column 6
(8) (Column 3 / Column 2) / 10
(9) (Column 4 / Column 2) / 10
(10) (Column 5 / Column 2) / 10
(11) (Column 6 / Column 2) / 10
(12) Column 8 + Column 9 + Column 10 + Column 11
(13) Class Billing kW Load Factor
(14) Column 2 x 1000 / 8,760 / Column 13 x 12
(15) Column 3 / Column 14
(16) Column 4 / Column 14
(17) Column 5 / Column 14
(18) Column 6 / Column 14
(19) Column 7 / Column 14

Duke Energy Florida
Calculation of Capacity Cost Recovery Factors by Rate Class
For the Year 2017

Docket No. 160001-EI
Exhibit__CAM-3, Part 3
Schedule E12-E
Page 2 of 2

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) Levy Production Demand Costs ($)	(6) CR3 Production Demand Costs ($)	(7) Capacity + Nuclear + ISFSI Production Demand Costs ($)	(13) Billing KW Load Factor (%)	(14) Projected Effective KW at Meter Level (kW)	(15) Capacity CCR Factor ($/kW-mo)	(16) ISFSI CCR Factor ($/kW-mo)	(17) Levy CCR Factor ($/kW-mo)	(18) CR3 CCR Factor ($/kW-mo)	(19) Capacity & Nuclear CCR Factor ($/kW-mo)
Residential														
RS-1, RST-1, RSL-1, RSL-2, RSS-1														
Secondary	60.755%	20,141,254	$225,773,930	$3,335,234	$0	$31,433,222	$260,542,386							
General Service Non-Demand														
GS-1, GST-1														
Secondary		1,837,382												
Primary		15,250												
Transmission		3,019												
TOTAL GS	4.340%	1,855,651	16,128,410	301,829	0	2,245,467	18,675,706							
General Service														
GS-2 Secondary	0.282%	170,272	1,048,594	10,585	0	145,990	1,205,169							
General Service Demand														
GSD-1, GSDT-1, SS-1														
Secondary		12,108,998								**3.18**	**0.04**	**0.00**	**0.44**	**3.67**
Primary		2,363,701								**3.15**	**0.04**	**0.00**	**0.44**	**3.63**
Transmission		8,437								**3.12**	**0.04**	**0.00**	**0.43**	**3.60**
TOTAL GSD	30.963%	14,481,136	115,064,327	1,444,523	0	16,019,753	132,528,603	54.90%	36,133,284					
Curtailable														
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3														
Secondary		-								**2.50**	**0.04**	**0.00**	**0.35**	**2.89**
Primary		131,275								**2.48**	**0.04**	**0.00**	**0.35**	**2.86**
Transmission		-								**2.45**	**0.04**	**0.00**	**0.34**	**2.83**
TOTAL CS	0.237%	131,275	882,238	14,618	0	122,829	1,019,685	51.00%	352,605					
Interruptible														
IS-1, IST-1, IS-2, IST-2, SS-2														
Secondary		87,039								**2.46**	**0.03**	**0.00**	**0.34**	**2.83**
Primary		1,641,106								**2.44**	**0.03**	**0.00**	**0.34**	**2.80**
Transmission		271,450								**2.41**	**0.03**	**0.00**	**0.33**	**2.77**
TOTAL IS	3.243%	1,999,595	12,050,639	155,332	0	1,677,742	13,883,713	55.90%	4,900,128					
Lighting														
LS-1 Secondary	0.179%	387,147	664,792	25,249	0	92,555	782,596							
Total	100.000%	39,166,331	$371,612,930	$5,287,371	$0	$51,737,557	$428,637,858							

Notes:

(1) From Schedule E12-D, Column 10
(2) Projected mWh sales at effective voltage level for Jan-Dec
(3) Column 1 x Total Recoverable Payments (Schedule E12-A)
(4) From Schedule E12-D, Column 12
(5) (Column 10 x Column 2) x 10
(6) Column 1 x Total Recoverable Payments (Schedule E12-A)
(7) Column 3 + Column 4 + Column 5 + Column 6
(8) (Column 3 / Column 2) / 10
(9) (Column 4 / Column 2) / 10
(10) (Column 5 / Column 2) / 10
(11) (Column 6 / Column 2) / 10
(12) Column 8 + Column 9 + Column 10 + Column 11
(13) Class Billing kW Load Factor
(14) Column 2 x 1000 / 8,760 / Column 13 x 12
(15) Column 3 / Column 14
(16) Column 4 / Column 14
(17) Column 5 / Column 14
(18) Column 6 / Column 14
(19) Column 7 / Column 14

***Calculation of Standby Service kW Charges:**

	Capacity + Nuclear Cost Cost	Effective kW	$/kW
Total GSD, CS, IS	$147,432,001	41,386,017	3.56
SS-1, 2, 3 - $/kW-mo	Secondary	Primary	Trans
Monthly - $3.56/kW * 10%	0.356	0.352	0.349
Daily - $3.56/kW / 21	0.170	0.168	0.167

REDACTED

Duke Energy Florida
Natural Gas and Oil 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-15	[redacted]						17,406,400	[redacted]		
Feb-15							14,828,000			
Mar-15							15,133,600			
Apr-15							17,874,900			
May-15							20,049,900			
Jun-15							21,510,400			
Jul-15							21,620,600			
Aug-15							22,922,000			
Sep-15							20,033,700			
Oct-15							17,807,100			
Nov-15							18,705,400			
Dec-15							19,176,900			
YTD	($225,543,645)	$0	($225,543,645)	139,177,500	0	139,177,500	227,068,900	61%	100%	0%

No. 2 Oil

	Savings/(Cost) on Hedges			Hedged Volumes (Gallons)						
Year	Financial	Physical	Total	Financial	Physical	Total Hedged	Actual Burn (Generation)	Hedged Burns	% Hedged with Financial	% Hedged with Physical
Jan-15	[redacted]						410,276	[redacted]		
Feb-15							1,364,045			
Mar-15							221,413			
Apr-15							375,413			
May-15							384,011			
Jun-15							317,903			
Jul-15							271,189			
Aug-15							591,941			
Sep-15							567,384			
Oct-15							294,697			
Nov-15							1,815,016			
Dec-15							312,713			
YTD	($261,097)	$0	($261,097)	504,000	0	504,000	6,926,001	7%	100%	0%

Note 1

Natural Gas Storage

	Savings/(Cost) on Hedges			Hedged Volumes (MMBtu's)						
Year	Financial	Physical	Total	Financial	Physical	Total Hedged	Actual Injections	Hedged Injections	% Hedged with Financial	% Hedged with Physical
Jun-15	$15,375	$0	$15,375	150,000	0	150,000	250,000	60%	100%	0%
YTD	$15,375	$0	$15,375	150,000	0	150,000	250,000	60%	100%	0%

Heating Oil - River Barge - Fuel Surcharge Hedges

	Savings/(Cost) on Hedges			Hedged Volumes (Gallons)						
Year	Financial	Physical	Total	Financial	Physical	Total Hedged	Estimated Exposure	Hedged Exposure	% Hedged with Financial	% Hedged with Physical
Jan-15	[redacted]						583,589	[redacted]		
Feb-15							573,940			
Mar-15							570,206			
Apr-15							537,905			
May-15							522,687			
Jun-15							517,576			
Jul-15							530,616			
Aug-15							524,103			
Sep-15							517,631			
Oct-15							359,213			
Nov-15							361,686			
Dec-15							432,284			
YTD	($645,170)	$0	($645,170)	3,276,000	0	3,276,000	6,031,436	54%	100%	0%

Heating Oil - Rail - Fuel Surcharge Hedges

	Savings/(Cost) on Hedges			Hedged Volumes (Gallons)						
Year	Financial	Physical	Total	Financial	Physical	Total Hedged	Estimated Exposure	Hedged Exposure	% Hedged with Financial	% Hedged with Physical
Jan-15	[redacted]						108,481	[redacted]		
Feb-15							100,994			
Mar-15							100,994			
Apr-15							100,994			
May-15							141,075			
Jun-15							125,400			
Jul-15							141,075			
Aug-15							141,075			
Sep-15							125,400			
YTD	($54,178)	$0	($54,178)	504,000	0	504,000	1,085,488	46%	100%	0%

Note 2

[redacted]e 1: For the period of January 2015 through December 2015, based on forecasted burns for 2015, DEF fuel oil hedge percentage was approximately [redacted]. This was above the minimum hedge target of [redacted] During 2015, actual fuel oil usage was higher than forecasts which resulted in the overall lower actual hedge percentage.

Note 2: As outlined in DEF's 2016 Risk Management Plan, with respect to estimated fuel surcharge exposures in its coal rail transportation agreement, given the reduction in rail shipments during the latter part of 2015, and the expiration of the rail agreement at the end of December 2015, DEF did not estimate or hedge rail exposures for periods beyond September 2015. For the twelve-month period of August 2014 through July 2015, DEF's estimated rail surcharge hedge percentage was approximately [redacted] Also, for the period of January 2015 through September 2015, DEF's overall rail surcharge hedge percentage was approximately [redacted] which was within the target range of [redacted] o [redacted]

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 8
PARTY: DUKE ENERGY FLORIDA, LLC – (DIRECT)
DESCRIPTION: Joseph McCallister JM-1T

As of December 31, 2015

DEF Gas Hedging Status
REDACTED

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	1/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub			$3.1890			
Financial	Financial Option	Put	1/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub			$3.1890			
Financial	Financial Option	Call	1/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub			$3.1890			
Financial	Financial Option	Put	1/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub			$3.1890			
Financial	Financial Option	Call	1/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT			$3.0900			
Financial	Financial Option	Put	1/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3223428	MerrilL ynchCom E EM	IFERC	Henry Hub			$3.1900			
Financial	Financial Swap		1/1/2015	3223434	Morgan Stanley E	IFERC	Henry Hub			$3.1900			
Financial	Financial Swap		1/1/2015	3223439	Morgan Stanley E	IFERC	Henry Hub			$3.1900			
Financial	Financial Swap		1/1/2015	3223546	Barclays Bank E	IFERC	Henry Hub			$3.1900			
Financial	Financial Swap		1/1/2015	3223547	JPMorganChase Bank E	IFERC	Henry Hub			$3.1900			
Financial	Financial Swap		1/1/2015	3223823	Barclays Bank E	NYMEX NG L1D	Henry Hub			$3.1890			
Financial	Financial Swap		1/1/2015	3223932	Citigroup Energy E	NYMEX NG L1D	Henry Hub			$3.1890			
Financial	Financial Swap		1/1/2015	3223958	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub			$3.1890			
Financial	Financial Swap		1/1/2015	3224035	Barclays Bank E	NYMEX NG L1D	Henry Hub			$3.1890			
Financial	Financial Swap		1/1/2015	3224087	Morgan Stanley E	NYMEX NG L1D	Henry Hub			$3.1890			
Financial	Financial Swap		1/1/2015	3224214	JPMorganChase Bank E	IFERC	Transco Zone 4			$3.1900			
Financial	Financial Swap		1/1/2015	3224217	Macquarie Bank Ltd	IFERC	Transco Zone 4			$3.1900			
Financial	Financial Swap		1/1/2015	3224222	Barclays Bank E	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3224256	Barclays Bank E	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3224277	Citigroup Energy E	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3224279	Citigroup Energy E	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3224281	JPMorganChase Bank E	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3224350	JPMorganChase Bank E	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3224437	Morgan Stanley E	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3224613	Credit Suisse Intl	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3224619	JPMorganChase Bank E	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3224622	Barclays Bank E	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3224677	Macquarie Bank Ltd	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3224690	Credit Suisse Intl	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3224810	Citigroup Energy E	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3224832	Morgan Stanley E	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3224917	Morgan Stanley E	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3224920	Morgan Stanley E	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3224922	Citigroup Energy E	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3224924	Credit Suisse Intl	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3225051	MerrilL ynchCom E EM	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3225058	Credit Suisse Intl	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3225197	MerrilL ynchCom E EM	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3225871	BKMONTREAL	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3225886	Macquarie Bank Ltd	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3225889	BKMONTREAL	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3225948	MerrilL ynchCom E EM	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3226567	BKMONTREAL	IFERC	Transco Zone 4			$3.1900			
Financial	Financial Swap		1/1/2015	3226688	BKMONTREAL	IFERC	Transco Zone 4			$3.1900			
Financial	Financial Swap		1/1/2015	3226756	BKMONTREAL	IFERC	Transco Zone 4			$3.1900			
Financial	Financial Swap		1/1/2015	3226759	BKMONTREAL	IFERC	Transco Zone 4			$3.1900			
Financial	Financial Swap		1/1/2015	3226760	MerrilL ynchCom E EM	IFERC	Transco Zone 4			$3.1900			
Financial	Financial Swap		1/1/2015	3226761	BKMONTREAL	IFERC	Transco Zone 4			$3.1900			
Financial	Financial Swap		1/1/2015	3226794	JPMorganChase Bank E	IFERC	Transco Zone 4			$3.1900			
Financial	Financial Swap		1/1/2015	3226798	BKMONTREAL	IFERC	Transco Zone 4			$3.1900			
Financial	Financial Swap		1/1/2015	3238362	MerrilL ynchCom E EM	IFERC	Henry Hub			$3.1900			
Financial	Financial Swap		1/1/2015	3240193	MerrilL ynchCom E EM	IFERC	Henry Hub			$3.1900			
Financial	Financial Swap		1/1/2015	3240194	JPMorganChase Bank E	IFERC	Henry Hub			$3.1900			
Financial	Financial Swap		1/1/2015	3243454	BKMONTREAL	IFERC	Henry Hub			$3.1900			
Financial	Financial Swap		1/1/2015	3248424	MerrilL ynchCom E EM	IFERC	CGT			$3.0900			
Financial	Financial Swap		1/1/2015	3250964	BKMONTREAL	IFERC	Transco Zone 4			$3.1900			
Financial	Financial Swap		1/1/2015	3254125	JPMorganChase Bank E	IFERC	Transco Zone 4			$3.1900			
Financial	Financial Swap		1/1/2015	3256079	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub			$3.1890			
			1/1/2015 Total									17,406,400	

Financial	Financial Option	Call	2/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub	[redacted]	$2.8660	[redacted]		
Financial	Financial Option	Put	2/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub	[redacted]	$2.8660	[redacted]		
Financial	Financial Option	Call	2/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub	[redacted]	$2.8660	[redacted]		
Financial	Financial Option	Put	2/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub	[redacted]	$2.8660	[redacted]		
Financial	Financial Option	Call	2/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Option	Put	2/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3223428	MerrilL ynchCom E EM	IFERC	Henry Hub	[redacted]	$2.8700	[redacted]		
Financial	Financial Swap		2/1/2015	3223434	Morgan Stanley E	IFERC	Henry Hub	[redacted]	$2.8700	[redacted]		
Financial	Financial Swap		2/1/2015	3223439	Morgan Stanley E	IFERC	Henry Hub	[redacted]	$2.8700	[redacted]		
Financial	Financial Swap		2/1/2015	3223546	Barclays Bank E	IFERC	Henry Hub	[redacted]	$2.8700	[redacted]		
Financial	Financial Swap		2/1/2015	3223547	JPMorganChase Bank E	IFERC	Henry Hub	[redacted]	$2.8700	[redacted]		
Financial	Financial Swap		2/1/2015	3223823	Barclays Bank E	NYMEX NG L1D	Henry Hub	[redacted]	$2.8660	[redacted]		
Financial	Financial Swap		2/1/2015	3223932	Citigroup Energy E	NYMEX NG L1D	Henry Hub	[redacted]	$2.8660	[redacted]		
Financial	Financial Swap		2/1/2015	3223958	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub	[redacted]	$2.8660	[redacted]		
Financial	Financial Swap		2/1/2015	3224035	Barclays Bank E	NYMEX NG L1D	Henry Hub	[redacted]	$2.8660	[redacted]		
Financial	Financial Swap		2/1/2015	3224087	Morgan Stanley E	NYMEX NG L1D	Henry Hub	[redacted]	$2.8660	[redacted]		
Financial	Financial Swap		2/1/2015	3224214	JPMorganChase Bank E	IFERC	Transco Zone 4	[redacted]	$2.8800	[redacted]		
Financial	Financial Swap		2/1/2015	3224217	Macquarie Bank Ltd	IFERC	Transco Zone 4	[redacted]	$2.8800	[redacted]		
Financial	Financial Swap		2/1/2015	3224222	Barclays Bank E	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3224256	Barclays Bank E	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3224277	Citigroup Energy E	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3224279	Citigroup Energy E	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3224281	JPMorganChase Bank E	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3224350	JPMorganChase Bank E	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3224437	Morgan Stanley E	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3224613	Credit Suisse Intl	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3224619	JPMorganChase Bank E	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3224622	Barclays Bank E	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3224677	Macquarie Bank Ltd	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3224690	Credit Suisse Intl	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3224810	Citigroup Energy E	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3224832	Morgan Stanley E	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3224917	Morgan Stanley E	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3224920	Morgan Stanley E	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3224922	Citigroup Energy E	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3224924	Credit Suisse Intl	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3225051	MerrilL ynchCom E EM	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3225058	Credit Suisse Intl	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3225197	MerrilL ynchCom E EM	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3225871	BKMONTREAL	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3225886	Macquarie Bank Ltd	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3225889	BKMONTREAL	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3225948	MerrilL ynchCom E EM	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3226567	BKMONTREAL	IFERC	Transco Zone 4	[redacted]	$2.8800	[redacted]		
Financial	Financial Swap		2/1/2015	3226688	BKMONTREAL	IFERC	Transco Zone 4	[redacted]	$2.8800	[redacted]		
Financial	Financial Swap		2/1/2015	3226756	BKMONTREAL	IFERC	Transco Zone 4	[redacted]	$2.8800	[redacted]		
Financial	Financial Swap		2/1/2015	3226759	BKMONTREAL	IFERC	Transco Zone 4	[redacted]	$2.8800	[redacted]		
Financial	Financial Swap		2/1/2015	3226760	MerrilL ynchCom E EM	IFERC	Transco Zone 4	[redacted]	$2.8800	[redacted]		
Financial	Financial Swap		2/1/2015	3226761	BKMONTREAL	IFERC	Transco Zone 4	[redacted]	$2.8800	[redacted]		
Financial	Financial Swap		2/1/2015	3226794	JPMorganChase Bank E	IFERC	Transco Zone 4	[redacted]	$2.8800	[redacted]		
Financial	Financial Swap		2/1/2015	3226798	BKMONTREAL	IFERC	Transco Zone 4	[redacted]	$2.8800	[redacted]		
Financial	Financial Swap		2/1/2015	3238362	MerrilL ynchCom E EM	IFERC	Henry Hub	[redacted]	$2.8700	[redacted]		
Financial	Financial Swap		2/1/2015	3240193	MerrilL ynchCom E EM	IFERC	Henry Hub	[redacted]	$2.8700	[redacted]		
Financial	Financial Swap		2/1/2015	3240194	JPMorganChase Bank E	IFERC	Henry Hub	[redacted]	$2.8700	[redacted]		
Financial	Financial Swap		2/1/2015	3243454	BKMONTREAL	IFERC	Henry Hub	[redacted]	$2.8700	[redacted]		
Financial	Financial Swap		2/1/2015	3248424	MerrilL ynchCom E EM	IFERC	CGT	[redacted]	$2.7800	[redacted]		
Financial	Financial Swap		2/1/2015	3250964	BKMONTREAL	IFERC	Transco Zone 4	[redacted]	$2.8800	[redacted]		
Financial	Financial Swap		2/1/2015	3254125	JPMorganChase Bank E	IFERC	Transco Zone 4	[redacted]	$2.8800	[redacted]		
Financial	Financial Swap		2/1/2015	3256079	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub	[redacted]	$2.8660	[redacted]		
			2/1/2015 Total					[redacted]		[redacted]	14,828,000	[redacted]

								[redacted]		[redacted]		
Financial	Financial Option	Call	3/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.8940			
Financial	Financial Option	Put	3/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.8940			
Financial	Financial Option	Call	3/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8940			
Financial	Financial Option	Put	3/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8940			
Financial	Financial Option	Call	3/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT		$2.8300			
Financial	Financial Option	Put	3/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3223428	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.9000			
Financial	Financial Swap		3/1/2015	3223434	Morgan Stanley E	IFERC	Henry Hub		$2.9000			
Financial	Financial Swap		3/1/2015	3223439	Morgan Stanley E	IFERC	Henry Hub		$2.9000			
Financial	Financial Swap		3/1/2015	3223546	Barclays Bank E	IFERC	Henry Hub		$2.9000			
Financial	Financial Swap		3/1/2015	3223547	JPMorganChase Bank E	IFERC	Henry Hub		$2.9000			
Financial	Financial Swap		3/1/2015	3223823	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.8940			
Financial	Financial Swap		3/1/2015	3223932	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.8940			
Financial	Financial Swap		3/1/2015	3223958	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$2.8940			
Financial	Financial Swap		3/1/2015	3224035	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.8940			
Financial	Financial Swap		3/1/2015	3224087	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8940			
Financial	Financial Swap		3/1/2015	3224214	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.8900			
Financial	Financial Swap		3/1/2015	3224217	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.8900			
Financial	Financial Swap		3/1/2015	3224222	Barclays Bank E	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3224256	Barclays Bank E	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3224277	Citigroup Energy E	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3224279	Citigroup Energy E	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3224281	JPMorganChase Bank E	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3224350	JPMorganChase Bank E	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3224437	Morgan Stanley E	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3224613	Credit Suisse Intl	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3224619	JPMorganChase Bank E	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3224622	Barclays Bank E	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3224677	Macquarie Bank Ltd	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3224690	Credit Suisse Intl	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3224810	Citigroup Energy E	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3224832	Morgan Stanley E	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3224917	Morgan Stanley E	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3224920	Morgan Stanley E	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3224922	Citigroup Energy E	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3224924	Credit Suisse Intl	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3225051	MerrilL ynchCom E EM	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3225058	Credit Suisse Intl	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3225197	MerrilL ynchCom E EM	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3225871	BKMONTREAL	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3225886	Macquarie Bank Ltd	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3225889	BKMONTREAL	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3225948	MerrilL ynchCom E EM	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3226567	BKMONTREAL	IFERC	Transco Zone 4		$2.8900			
Financial	Financial Swap		3/1/2015	3226688	BKMONTREAL	IFERC	Transco Zone 4		$2.8900			
Financial	Financial Swap		3/1/2015	3226756	BKMONTREAL	IFERC	Transco Zone 4		$2.8900			
Financial	Financial Swap		3/1/2015	3226759	BKMONTREAL	IFERC	Transco Zone 4		$2.8900			
Financial	Financial Swap		3/1/2015	3226760	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.8900			
Financial	Financial Swap		3/1/2015	3226761	BKMONTREAL	IFERC	Transco Zone 4		$2.8900			
Financial	Financial Swap		3/1/2015	3226794	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.8900			
Financial	Financial Swap		3/1/2015	3226798	BKMONTREAL	IFERC	Transco Zone 4		$2.8900			
Financial	Financial Swap		3/1/2015	3238362	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.9000			
Financial	Financial Swap		3/1/2015	3240193	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.9000			
Financial	Financial Swap		3/1/2015	3240194	JPMorganChase Bank E	IFERC	Henry Hub		$2.9000			
Financial	Financial Swap		3/1/2015	3243454	BKMONTREAL	IFERC	Henry Hub		$2.9000			
Financial	Financial Swap		3/1/2015	3248424	MerrilL ynchCom E EM	IFERC	CGT		$2.8300			
Financial	Financial Swap		3/1/2015	3250964	BKMONTREAL	IFERC	Transco Zone 4		$2.8900			
Financial	Financial Swap		3/1/2015	3254125	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.8900			
Financial	Financial Swap		3/1/2015	3256079	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8940			
		3/1/2015 Total									15,133,600	

Financial	Financial Option	Call	4/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub	[redacted]	$2.5900	[redacted]	
Financial	Financial Option	Put	4/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.5900		
Financial	Financial Option	Call	4/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.5900		
Financial	Financial Option	Put	4/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.5900		
Financial	Financial Option	Call	4/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT		$2.5100		
Financial	Financial Option	Put	4/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT		$2.5100		
Financial	Financial Option	Call	4/1/2015	3227519	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.5900		
Financial	Financial Option	Put	4/1/2015	3227519	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.5900		
Financial	Financial Option	Call	4/1/2015	3227521	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.5900		
Financial	Financial Option	Put	4/1/2015	3227521	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.5900		
Financial	Financial Option	Call	4/1/2015	3227767	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.5600		
Financial	Financial Option	Put	4/1/2015	3227767	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.5600		
Financial	Financial Swap		4/1/2015	3223326	JPMorganChase Bank E	IFERC	Henry Hub		$2.6100		
Financial	Financial Swap		4/1/2015	3223331	JPMorganChase Bank E	IFERC	Henry Hub		$2.6100		
Financial	Financial Swap		4/1/2015	3223333	Morgan Stanley E	IFERC	Henry Hub		$2.6100		
Financial	Financial Swap		4/1/2015	3223336	Morgan Stanley E	IFERC	Henry Hub		$2.6100		
Financial	Financial Swap		4/1/2015	3223424	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.6100		
Financial	Financial Swap		4/1/2015	3223426	Macquarie Bank Ltd	IFERC	Henry Hub		$2.6100		
Financial	Financial Swap		4/1/2015	3223428	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.6100		
Financial	Financial Swap		4/1/2015	3223432	JPMorganChase Bank E	IFERC	Henry Hub		$2.6100		
Financial	Financial Swap		4/1/2015	3223434	Morgan Stanley E	IFERC	Henry Hub		$2.6100		
Financial	Financial Swap		4/1/2015	3223439	Morgan Stanley E	IFERC	Henry Hub		$2.6100		
Financial	Financial Swap		4/1/2015	3223475	Morgan Stanley E	IFERC	Henry Hub		$2.6100		
Financial	Financial Swap		4/1/2015	3223537	Morgan Stanley E	IFERC	Henry Hub		$2.6100		
Financial	Financial Swap		4/1/2015	3223541	Morgan Stanley E	IFERC	Henry Hub		$2.6100		
Financial	Financial Swap		4/1/2015	3223544	JPMorganChase Bank E	IFERC	Henry Hub		$2.6100		
Financial	Financial Swap		4/1/2015	3223546	Barclays Bank E	IFERC	Henry Hub		$2.6100		
Financial	Financial Swap		4/1/2015	3223547	JPMorganChase Bank E	IFERC	Henry Hub		$2.6100		
Financial	Financial Swap		4/1/2015	3223550	Morgan Stanley E	IFERC	Henry Hub		$2.6100		
Financial	Financial Swap		4/1/2015	3223552	Barclays Bank E	IFERC	Henry Hub		$2.6100		
Financial	Financial Swap		4/1/2015	3223567	Credit Suisse Intl	IFERC	Henry Hub		$2.6100		
Financial	Financial Swap		4/1/2015	3223569	Morgan Stanley E	IFERC	Henry Hub		$2.6100		
Financial	Financial Swap		4/1/2015	3223742	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.5900		
Financial	Financial Swap		4/1/2015	3223744	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.5900		
Financial	Financial Swap		4/1/2015	3224216	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.5900		
Financial	Financial Swap		4/1/2015	3224219	Credit Suisse Intl	NYMEX NG L1D	Henry Hub		$2.5900		
Financial	Financial Swap		4/1/2015	3224220	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.5900		
Financial	Financial Swap		4/1/2015	3224229	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.5900		
Financial	Financial Swap		4/1/2015	3224232	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.5900		
Financial	Financial Swap		4/1/2015	3224245	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.5900		
Financial	Financial Swap		4/1/2015	3224252	Barclays Bank E	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224276	JPMorganChase Bank E	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224280	Barclays Bank E	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224337	Barclays Bank E	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224381	JPMorganChase Bank E	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224384	JPMorganChase Bank E	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224508	Morgan Stanley E	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224509	Morgan Stanley E	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224604	Credit Suisse Intl	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224618	JPMorganChase Bank E	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224620	Citigroup Energy E	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224621	JPMorganChase Bank E	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224640	Macquarie Bank Ltd	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224679	Barclays Bank E	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224681	JPMorganChase Bank E	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224682	Citigroup Energy E	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224683	JPMorganChase Bank E	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224684	MerrilL ynchCom E EM	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224693	JPMorganChase Bank E	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224697	Macquarie Bank Ltd	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224807	Credit Suisse Intl	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224813	MerrilL ynchCom E EM	IFERC	CGT		$2.5100		
Financial	Financial Swap		4/1/2015	3224815	Credit Suisse Intl	IFERC	Transco Zone 4		$2.5600		
Financial	Financial Swap		4/1/2015	3224817	Barclays Bank E	IFERC	Transco Zone 4		$2.5600		
Financial	Financial Swap		4/1/2015	3224818	Morgan Stanley E	IFERC	Transco Zone 4		$2.5600		
Financial	Financial Swap		4/1/2015	3224826	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.5600		
Financial	Financial Swap		4/1/2015	3224914	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.5600		

Financial	Financial Swap		4/1/2015	3224915	Morgan Stanley E	IFERC	Transco Zone 4	[redacted]	$2.5600	[redacted]		
Financial	Financial Swap		4/1/2015	3224916	Morgan Stanley E	IFERC	Transco Zone 4		$2.5600			
Financial	Financial Swap		4/1/2015	3224919	Citigroup Energy E	IFERC	Transco Zone 4		$2.5600			
Financial	Financial Swap		4/1/2015	3224921	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.5600			
Financial	Financial Swap		4/1/2015	3224923	Credit Suisse Intl	IFERC	Transco Zone 4		$2.5600			
Financial	Financial Swap		4/1/2015	3224925	Citigroup Energy E	IFERC	Transco Zone 4		$2.5600			
Financial	Financial Swap		4/1/2015	3224927	Credit Suisse Intl	IFERC	Transco Zone 4		$2.5600			
Financial	Financial Swap		4/1/2015	3225044	Morgan Stanley E	IFERC	Transco Zone 4		$2.5600			
Financial	Financial Swap		4/1/2015	3225050	JPMorganChase Bank E	IFERC	CGT		$2.5100			
Financial	Financial Swap		4/1/2015	3225057	MerrilL ynchCom E EM	IFERC	CGT		$2.5100			
Financial	Financial Swap		4/1/2015	3225265	Morgan Stanley E	IFERC	CGT		$2.5100			
Financial	Financial Swap		4/1/2015	3226557	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.5600			
Financial	Financial Swap		4/1/2015	3267250	JPMorganChase Bank E	IFERC	CGT		$2.5100			
Financial	Financial Swap		4/1/2015	3283784	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.5600			
Financial	Financial Swap		4/1/2015	3284453	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.5600			
Financial	Financial Swap		4/1/2015	3286344	Citigroup Energy E	IFERC	Transco Zone 4		$2.5600			
Financial	Financial Swap		4/1/2015	3294866	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.5600			
Financial	Financial Swap		4/1/2015	3306466	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.5900			
		4/1/2015 Total									17,874,900	[redacted]

Financial	Financial Option	Call	5/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub	[redacted]	$2.5170	[redacted]	
Financial	Financial Option	Put	5/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Option	Call	5/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Option	Put	5/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Option	Call	5/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT		$2.4400		
Financial	Financial Option	Put	5/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT		$2.4400		
Financial	Financial Option	Call	5/1/2015	3227518	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.5300		
Financial	Financial Option	Put	5/1/2015	3227518	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.5300		
Financial	Financial Option	Call	5/1/2015	3227519	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Option	Put	5/1/2015	3227519	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Option	Call	5/1/2015	3227521	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Option	Put	5/1/2015	3227521	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Option	Call	5/1/2015	3227767	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.5000		
Financial	Financial Option	Put	5/1/2015	3227767	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.5000		
Financial	Financial Option	Call	5/1/2015	3238363	BKMONTREAL	IFERC	Henry Hub		$2.5300		
Financial	Financial Option	Put	5/1/2015	3238363	BKMONTREAL	IFERC	Henry Hub		$2.5300		
Financial	Financial Option	Call	5/1/2015	3246480	Citigroup Energy E	IFERC	Henry Hub		$2.5300		
Financial	Financial Option	Put	5/1/2015	3246480	Citigroup Energy E	IFERC	Henry Hub		$2.5300		
Financial	Financial Option	Call	5/1/2015	3251386	BKMONTREAL	IFERC	Henry Hub		$2.5300		
Financial	Financial Option	Put	5/1/2015	3251386	BKMONTREAL	IFERC	Henry Hub		$2.5300		
Financial	Financial Option	Call	5/1/2015	3264163	JPMorganChase Bank E	IFERC	Henry Hub		$2.5300		
Financial	Financial Option	Put	5/1/2015	3264163	JPMorganChase Bank E	IFERC	Henry Hub		$2.5300		
Financial	Financial Option	Call	5/1/2015	3266285	Morgan Stanley E	IFERC	Henry Hub		$2.5300		
Financial	Financial Option	Put	5/1/2015	3266285	Morgan Stanley E	IFERC	Henry Hub		$2.5300		
Financial	Financial Option	Call	5/1/2015	3279679	Citigroup Energy E	IFERC	Henry Hub		$2.5300		
Financial	Financial Option	Put	5/1/2015	3279679	Citigroup Energy E	IFERC	Henry Hub		$2.5300		
Financial	Financial Option	Call	5/1/2015	3292219	Citigroup Energy E	IFERC	Henry Hub		$2.5300		
Financial	Financial Option	Put	5/1/2015	3292219	Citigroup Energy E	IFERC	Henry Hub		$2.5300		
Financial	Financial Option	Call	5/1/2015	3298153	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Option	Put	5/1/2015	3298153	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Option	Call	5/1/2015	3301239	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Option	Put	5/1/2015	3301239	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Option	Call	5/1/2015	3304156	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Option	Put	5/1/2015	3304156	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Option	Call	5/1/2015	3310401	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Option	Put	5/1/2015	3310401	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Option	Call	5/1/2015	3312102	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Option	Put	5/1/2015	3312102	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Option	Call	5/1/2015	3317624	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Option	Put	5/1/2015	3317624	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Option	Call	5/1/2015	3321624	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Option	Put	5/1/2015	3321624	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Swap		5/1/2015	3223326	JPMorganChase Bank E	IFERC	Henry Hub		$2.5300		
Financial	Financial Swap		5/1/2015	3223331	JPMorganChase Bank E	IFERC	Henry Hub		$2.5300		
Financial	Financial Swap		5/1/2015	3223333	Morgan Stanley E	IFERC	Henry Hub		$2.5300		
Financial	Financial Swap		5/1/2015	3223336	Morgan Stanley E	IFERC	Henry Hub		$2.5300		
Financial	Financial Swap		5/1/2015	3223424	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.5300		
Financial	Financial Swap		5/1/2015	3223426	Macquarie Bank Ltd	IFERC	Henry Hub		$2.5300		
Financial	Financial Swap		5/1/2015	3223428	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.5300		
Financial	Financial Swap		5/1/2015	3223432	JPMorganChase Bank E	IFERC	Henry Hub		$2.5300		
Financial	Financial Swap		5/1/2015	3223434	Morgan Stanley E	IFERC	Henry Hub		$2.5300		
Financial	Financial Swap		5/1/2015	3223439	Morgan Stanley E	IFERC	Henry Hub		$2.5300		
Financial	Financial Swap		5/1/2015	3223475	Morgan Stanley E	IFERC	Henry Hub		$2.5300		
Financial	Financial Swap		5/1/2015	3223537	Morgan Stanley E	IFERC	Henry Hub		$2.5300		
Financial	Financial Swap		5/1/2015	3223541	Morgan Stanley E	IFERC	Henry Hub		$2.5300		
Financial	Financial Swap		5/1/2015	3223544	JPMorganChase Bank E	IFERC	Henry Hub		$2.5300		
Financial	Financial Swap		5/1/2015	3223546	Barclays Bank E	IFERC	Henry Hub		$2.5300		
Financial	Financial Swap		5/1/2015	3223547	JPMorganChase Bank E	IFERC	Henry Hub		$2.5300		
Financial	Financial Swap		5/1/2015	3223550	Morgan Stanley E	IFERC	Henry Hub		$2.5300		
Financial	Financial Swap		5/1/2015	3223552	Barclays Bank E	IFERC	Henry Hub		$2.5300		
Financial	Financial Swap		5/1/2015	3223567	Credit Suisse Intl	IFERC	Henry Hub		$2.5300		
Financial	Financial Swap		5/1/2015	3223569	Morgan Stanley E	IFERC	Henry Hub		$2.5300		
Financial	Financial Swap		5/1/2015	3223742	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Swap		5/1/2015	3223744	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Swap		5/1/2015	3224216	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Swap		5/1/2015	3224219	Credit Suisse Intl	NYMEX NG L1D	Henry Hub		$2.5170		
Financial	Financial Swap		5/1/2015	3224220	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.5170		

Financial	Financial Swap		5/1/2015	3224229	Barclays Bank E	NYMEX NG L1D	Henry Hub	[redacted]	$2.5170	[redacted]		
Financial	Financial Swap		5/1/2015	3224232	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.5170			
Financial	Financial Swap		5/1/2015	3224245	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.5170			
Financial	Financial Swap		5/1/2015	3224252	Barclays Bank E	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224276	JPMorganChase Bank E	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224280	Barclays Bank E	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224337	Barclays Bank E	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224381	JPMorganChase Bank E	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224384	JPMorganChase Bank E	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224508	Morgan Stanley E	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224509	Morgan Stanley E	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224604	Credit Suisse Intl	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224618	JPMorganChase Bank E	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224620	Citigroup Energy E	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224621	JPMorganChase Bank E	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224640	Macquarie Bank Ltd	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224679	Barclays Bank E	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224681	JPMorganChase Bank E	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224682	Citigroup Energy E	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224683	JPMorganChase Bank E	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224684	MerrilL ynchCom E EM	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224693	JPMorganChase Bank E	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224697	Macquarie Bank Ltd	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224807	Credit Suisse Intl	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224813	MerrilL ynchCom E EM	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3224815	Credit Suisse Intl	IFERC	Transco Zone 4		$2.5000			
Financial	Financial Swap		5/1/2015	3224817	Barclays Bank E	IFERC	Transco Zone 4		$2.5000			
Financial	Financial Swap		5/1/2015	3224818	Morgan Stanley E	IFERC	Transco Zone 4		$2.5000			
Financial	Financial Swap		5/1/2015	3224826	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.5000			
Financial	Financial Swap		5/1/2015	3224914	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.5000			
Financial	Financial Swap		5/1/2015	3224915	Morgan Stanley E	IFERC	Transco Zone 4		$2.5000			
Financial	Financial Swap		5/1/2015	3224916	Morgan Stanley E	IFERC	Transco Zone 4		$2.5000			
Financial	Financial Swap		5/1/2015	3224919	Citigroup Energy E	IFERC	Transco Zone 4		$2.5000			
Financial	Financial Swap		5/1/2015	3224921	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.5000			
Financial	Financial Swap		5/1/2015	3224923	Credit Suisse Intl	IFERC	Transco Zone 4		$2.5000			
Financial	Financial Swap		5/1/2015	3224925	Citigroup Energy E	IFERC	Transco Zone 4		$2.5000			
Financial	Financial Swap		5/1/2015	3224927	Credit Suisse Intl	IFERC	Transco Zone 4		$2.5000			
Financial	Financial Swap		5/1/2015	3225044	Morgan Stanley E	IFERC	Transco Zone 4		$2.5000			
Financial	Financial Swap		5/1/2015	3225050	JPMorganChase Bank E	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3225057	MerrilL ynchCom E EM	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3225265	Morgan Stanley E	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3226557	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.5000			
Financial	Financial Swap		5/1/2015	3228840	BKMONTREAL	IFERC	Henry Hub		$2.5300			
Financial	Financial Swap		5/1/2015	3267250	JPMorganChase Bank E	IFERC	CGT		$2.4400			
Financial	Financial Swap		5/1/2015	3283784	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.5000			
Financial	Financial Swap		5/1/2015	3284453	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.5000			
Financial	Financial Swap		5/1/2015	3286344	Citigroup Energy E	IFERC	Transco Zone 4		$2.5000			
Financial	Financial Swap		5/1/2015	3294866	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.5000			
Financial	Financial Swap		5/1/2015	3297904	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.5170			
Financial	Financial Swap		5/1/2015	3306466	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.5170			
Financial	Financial Swap		5/1/2015	3307910	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.5170			
Financial	Financial Swap		5/1/2015	3321455	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$2.5170			
Financial	Financial Swap		5/1/2015	3322457	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.5170			
Financial	Financial Swap		5/1/2015	3323023	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.5000			
		5/1/2015 Total									20,049,900	[redacted]

Financial	Financial Option	Call	6/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub	[redacted]	$2.8150	[redacted]		
Financial	Financial Option	Put	6/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Call	6/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Put	6/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Call	6/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT		$2.7200			
Financial	Financial Option	Put	6/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT		$2.7200			
Financial	Financial Option	Call	6/1/2015	3227518	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.8200			
Financial	Financial Option	Put	6/1/2015	3227518	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.8200			
Financial	Financial Option	Call	6/1/2015	3227519	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Put	6/1/2015	3227519	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Call	6/1/2015	3227521	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Put	6/1/2015	3227521	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Call	6/1/2015	3227767	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Option	Put	6/1/2015	3227767	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Option	Call	6/1/2015	3238363	BKMONTREAL	IFERC	Henry Hub		$2.8200			
Financial	Financial Option	Put	6/1/2015	3238363	BKMONTREAL	IFERC	Henry Hub		$2.8200			
Financial	Financial Option	Call	6/1/2015	3246480	Citigroup Energy E	IFERC	Henry Hub		$2.8200			
Financial	Financial Option	Put	6/1/2015	3246480	Citigroup Energy E	IFERC	Henry Hub		$2.8200			
Financial	Financial Option	Call	6/1/2015	3251386	BKMONTREAL	IFERC	Henry Hub		$2.8200			
Financial	Financial Option	Put	6/1/2015	3251386	BKMONTREAL	IFERC	Henry Hub		$2.8200			
Financial	Financial Option	Call	6/1/2015	3264163	JPMorganChase Bank E	IFERC	Henry Hub		$2.8200			
Financial	Financial Option	Put	6/1/2015	3264163	JPMorganChase Bank E	IFERC	Henry Hub		$2.8200			
Financial	Financial Option	Call	6/1/2015	3266285	Morgan Stanley E	IFERC	Henry Hub		$2.8200			
Financial	Financial Option	Put	6/1/2015	3266285	Morgan Stanley E	IFERC	Henry Hub		$2.8200			
Financial	Financial Option	Call	6/1/2015	3279679	Citigroup Energy E	IFERC	Henry Hub		$2.8200			
Financial	Financial Option	Put	6/1/2015	3279679	Citigroup Energy E	IFERC	Henry Hub		$2.8200			
Financial	Financial Option	Call	6/1/2015	3292219	Citigroup Energy E	IFERC	Henry Hub		$2.8200			
Financial	Financial Option	Put	6/1/2015	3292219	Citigroup Energy E	IFERC	Henry Hub		$2.8200			
Financial	Financial Option	Call	6/1/2015	3298153	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Put	6/1/2015	3298153	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Call	6/1/2015	3301239	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Put	6/1/2015	3301239	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Call	6/1/2015	3304156	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Put	6/1/2015	3304156	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Call	6/1/2015	3310401	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Put	6/1/2015	3310401	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Call	6/1/2015	3312102	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Put	6/1/2015	3312102	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Call	6/1/2015	3317624	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Put	6/1/2015	3317624	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Call	6/1/2015	3321624	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Put	6/1/2015	3321624	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Call	6/1/2015	3327183	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Put	6/1/2015	3327183	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Call	6/1/2015	3328119	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Option	Put	6/1/2015	3328119	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Swap		6/1/2015	3223326	JPMorganChase Bank E	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3223331	JPMorganChase Bank E	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3223333	Morgan Stanley E	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3223336	Morgan Stanley E	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3223424	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3223426	Macquarie Bank Ltd	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3223428	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3223432	JPMorganChase Bank E	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3223434	Morgan Stanley E	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3223439	Morgan Stanley E	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3223475	Morgan Stanley E	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3223537	Morgan Stanley E	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3223541	Morgan Stanley E	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3223544	JPMorganChase Bank E	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3223546	Barclays Bank E	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3223547	JPMorganChase Bank E	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3223550	Morgan Stanley E	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3223552	Barclays Bank E	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3223567	Credit Suisse Intl	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3223569	Morgan Stanley E	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3223742	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.8150			

Financial	Financial Swap		6/1/2015	3223744	Barclays Bank E	NYMEX NG L1D	Henry Hub	[redacted]	$2.8150	[redacted]		
Financial	Financial Swap		6/1/2015	3224216	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Swap		6/1/2015	3224219	Credit Suisse Intl	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Swap		6/1/2015	3224220	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Swap		6/1/2015	3224229	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Swap		6/1/2015	3224232	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Swap		6/1/2015	3224245	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Swap		6/1/2015	3224252	Barclays Bank E	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224276	JPMorganChase Bank E	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224280	Barclays Bank E	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224337	Barclays Bank E	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224381	JPMorganChase Bank E	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224384	JPMorganChase Bank E	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224508	Morgan Stanley E	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224509	Morgan Stanley E	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224604	Credit Suisse Intl	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224618	JPMorganChase Bank E	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224620	Citigroup Energy E	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224621	JPMorganChase Bank E	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224640	Macquarie Bank Ltd	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224679	Barclays Bank E	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224681	JPMorganChase Bank E	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224682	Citigroup Energy E	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224683	JPMorganChase Bank E	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224684	MerrilL ynchCom E EM	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224693	JPMorganChase Bank E	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224697	Macquarie Bank Ltd	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224807	Credit Suisse Intl	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224813	MerrilL ynchCom E EM	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3224815	Credit Suisse Intl	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Swap		6/1/2015	3224817	Barclays Bank E	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Swap		6/1/2015	3224818	Morgan Stanley E	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Swap		6/1/2015	3224826	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Swap		6/1/2015	3224914	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Swap		6/1/2015	3224915	Morgan Stanley E	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Swap		6/1/2015	3224916	Morgan Stanley E	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Swap		6/1/2015	3224919	Citigroup Energy E	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Swap		6/1/2015	3224921	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Swap		6/1/2015	3224923	Credit Suisse Intl	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Swap		6/1/2015	3224925	Citigroup Energy E	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Swap		6/1/2015	3224927	Credit Suisse Intl	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Swap		6/1/2015	3225044	Morgan Stanley E	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Swap		6/1/2015	3225050	JPMorganChase Bank E	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3225057	MerrilL ynchCom E EM	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3225265	Morgan Stanley E	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3226557	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Swap		6/1/2015	3228840	BKMONTREAL	IFERC	Henry Hub		$2.8200			
Financial	Financial Swap		6/1/2015	3267250	JPMorganChase Bank E	IFERC	CGT		$2.7200			
Financial	Financial Swap		6/1/2015	3283784	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Swap		6/1/2015	3284453	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Swap		6/1/2015	3286344	Citigroup Energy E	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Swap		6/1/2015	3294866	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Swap		6/1/2015	3297904	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Swap		6/1/2015	3306466	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Swap		6/1/2015	3307910	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Swap		6/1/2015	3321455	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Swap		6/1/2015	3322457	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.8150			
Financial	Financial Swap		6/1/2015	3323023	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Swap		6/1/2015	3324163	Citigroup Energy E	IFERC	Transco Zone 4		$2.8000			
Financial	Financial Swap		6/1/2015	3328730	BKMONTREAL	IFERC	Columbia Gulf		$2.7200			
		6/1/2015 Total									21,510,400	

Financial	Financial Option	Call	7/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub	[redacted]	$2.7730	[redacted]	
Financial	Financial Option	Put	7/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Call	7/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Put	7/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Call	7/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT		$2.7100		
Financial	Financial Option	Put	7/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT		$2.7100		
Financial	Financial Option	Call	7/1/2015	3227518	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.7700		
Financial	Financial Option	Put	7/1/2015	3227518	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.7700		
Financial	Financial Option	Call	7/1/2015	3227519	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Put	7/1/2015	3227519	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Call	7/1/2015	3227521	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Put	7/1/2015	3227521	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Call	7/1/2015	3227767	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Option	Put	7/1/2015	3227767	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Option	Call	7/1/2015	3238363	BKMONTREAL	IFERC	Henry Hub		$2.7700		
Financial	Financial Option	Put	7/1/2015	3238363	BKMONTREAL	IFERC	Henry Hub		$2.7700		
Financial	Financial Option	Call	7/1/2015	3246480	Citigroup Energy E	IFERC	Henry Hub		$2.7700		
Financial	Financial Option	Put	7/1/2015	3246480	Citigroup Energy E	IFERC	Henry Hub		$2.7700		
Financial	Financial Option	Call	7/1/2015	3251386	BKMONTREAL	IFERC	Henry Hub		$2.7700		
Financial	Financial Option	Put	7/1/2015	3251386	BKMONTREAL	IFERC	Henry Hub		$2.7700		
Financial	Financial Option	Call	7/1/2015	3264163	JPMorganChase Bank E	IFERC	Henry Hub		$2.7700		
Financial	Financial Option	Put	7/1/2015	3264163	JPMorganChase Bank E	IFERC	Henry Hub		$2.7700		
Financial	Financial Option	Call	7/1/2015	3266285	Morgan Stanley E	IFERC	Henry Hub		$2.7700		
Financial	Financial Option	Put	7/1/2015	3266285	Morgan Stanley E	IFERC	Henry Hub		$2.7700		
Financial	Financial Option	Call	7/1/2015	3279679	Citigroup Energy E	IFERC	Henry Hub		$2.7700		
Financial	Financial Option	Put	7/1/2015	3279679	Citigroup Energy E	IFERC	Henry Hub		$2.7700		
Financial	Financial Option	Call	7/1/2015	3292219	Citigroup Energy E	IFERC	Henry Hub		$2.7700		
Financial	Financial Option	Put	7/1/2015	3292219	Citigroup Energy E	IFERC	Henry Hub		$2.7700		
Financial	Financial Option	Call	7/1/2015	3298153	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Put	7/1/2015	3298153	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Call	7/1/2015	3301239	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Put	7/1/2015	3301239	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Call	7/1/2015	3304156	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Put	7/1/2015	3304156	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Call	7/1/2015	3310401	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Put	7/1/2015	3310401	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Call	7/1/2015	3312102	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Put	7/1/2015	3312102	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Call	7/1/2015	3317624	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Put	7/1/2015	3317624	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Call	7/1/2015	3321624	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Put	7/1/2015	3321624	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Call	7/1/2015	3327183	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Put	7/1/2015	3327183	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Call	7/1/2015	3328119	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Put	7/1/2015	3328119	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Call	7/1/2015	3332907	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Put	7/1/2015	3332907	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Call	7/1/2015	3334101	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Option	Put	7/1/2015	3334101	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Option	Call	7/1/2015	3336012	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Option	Put	7/1/2015	3336012	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Option	Call	7/1/2015	3336225	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Option	Put	7/1/2015	3336225	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Swap		7/1/2015	3223326	JPMorganChase Bank E	IFERC	Henry Hub		$2.7700		
Financial	Financial Swap		7/1/2015	3223331	JPMorganChase Bank E	IFERC	Henry Hub		$2.7700		
Financial	Financial Swap		7/1/2015	3223333	Morgan Stanley E	IFERC	Henry Hub		$2.7700		
Financial	Financial Swap		7/1/2015	3223336	Morgan Stanley E	IFERC	Henry Hub		$2.7700		
Financial	Financial Swap		7/1/2015	3223424	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.7700		
Financial	Financial Swap		7/1/2015	3223426	Macquarie Bank Ltd	IFERC	Henry Hub		$2.7700		
Financial	Financial Swap		7/1/2015	3223428	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.7700		
Financial	Financial Swap		7/1/2015	3223432	JPMorganChase Bank E	IFERC	Henry Hub		$2.7700		
Financial	Financial Swap		7/1/2015	3223434	Morgan Stanley E	IFERC	Henry Hub		$2.7700		
Financial	Financial Swap		7/1/2015	3223439	Morgan Stanley E	IFERC	Henry Hub		$2.7700		
Financial	Financial Swap		7/1/2015	3223475	Morgan Stanley E	IFERC	Henry Hub		$2.7700		
Financial	Financial Swap		7/1/2015	3223537	Morgan Stanley E	IFERC	Henry Hub		$2.7700		
Financial	Financial Swap		7/1/2015	3223541	Morgan Stanley E	IFERC	Henry Hub		$2.7700		

Financial	Financial Swap		7/1/2015	3223544	JPMorganChase Bank E	IFERC	Henry Hub	[redacted]	$2.7700	[redacted]	
Financial	Financial Swap		7/1/2015	3223546	Barclays Bank E	IFERC	Henry Hub		$2.7700		
Financial	Financial Swap		7/1/2015	3223547	JPMorganChase Bank E	IFERC	Henry Hub		$2.7700		
Financial	Financial Swap		7/1/2015	3223550	Morgan Stanley E	IFERC	Henry Hub		$2.7700		
Financial	Financial Swap		7/1/2015	3223552	Barclays Bank E	IFERC	Henry Hub		$2.7700		
Financial	Financial Swap		7/1/2015	3223567	Credit Suisse Intl	IFERC	Henry Hub		$2.7700		
Financial	Financial Swap		7/1/2015	3223569	Morgan Stanley E	IFERC	Henry Hub		$2.7700		
Financial	Financial Swap		7/1/2015	3223742	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Swap		7/1/2015	3223744	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Swap		7/1/2015	3224216	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Swap		7/1/2015	3224219	Credit Suisse Intl	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Swap		7/1/2015	3224220	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Swap		7/1/2015	3224229	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Swap		7/1/2015	3224232	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Swap		7/1/2015	3224245	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Swap		7/1/2015	3224252	Barclays Bank E	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224276	JPMorganChase Bank E	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224280	Barclays Bank E	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224337	Barclays Bank E	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224381	JPMorganChase Bank E	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224384	JPMorganChase Bank E	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224508	Morgan Stanley E	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224509	Morgan Stanley E	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224604	Credit Suisse Intl	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224618	JPMorganChase Bank E	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224620	Citigroup Energy E	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224621	JPMorganChase Bank E	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224640	Macquarie Bank Ltd	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224679	Barclays Bank E	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224681	JPMorganChase Bank E	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224682	Citigroup Energy E	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224683	JPMorganChase Bank E	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224684	MerrilL ynchCom E EM	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224693	JPMorganChase Bank E	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224697	Macquarie Bank Ltd	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224807	Credit Suisse Intl	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224813	MerrilL ynchCom E EM	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3224815	Credit Suisse Intl	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		7/1/2015	3224817	Barclays Bank E	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		7/1/2015	3224818	Morgan Stanley E	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		7/1/2015	3224826	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		7/1/2015	3224914	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		7/1/2015	3224915	Morgan Stanley E	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		7/1/2015	3224916	Morgan Stanley E	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		7/1/2015	3224919	Citigroup Energy E	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		7/1/2015	3224921	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		7/1/2015	3224923	Credit Suisse Intl	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		7/1/2015	3224925	Citigroup Energy E	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		7/1/2015	3224927	Credit Suisse Intl	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		7/1/2015	3225044	Morgan Stanley E	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		7/1/2015	3225050	JPMorganChase Bank E	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3225057	MerrilL ynchCom E EM	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3225265	Morgan Stanley E	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3226557	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		7/1/2015	3228840	BKMONTREAL	IFERC	Henry Hub		$2.7700		
Financial	Financial Swap		7/1/2015	3267250	JPMorganChase Bank E	IFERC	CGT		$2.7100		
Financial	Financial Swap		7/1/2015	3283784	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		7/1/2015	3284453	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		7/1/2015	3286344	Citigroup Energy E	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		7/1/2015	3294866	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		7/1/2015	3297904	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Swap		7/1/2015	3306466	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Swap		7/1/2015	3307910	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Swap		7/1/2015	3321455	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Swap		7/1/2015	3322457	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.7730		
Financial	Financial Swap		7/1/2015	3323023	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		7/1/2015	3324163	Citigroup Energy E	IFERC	Transco Zone 4		$2.7900		
Financial	Financial Swap		7/1/2015	3328730	BKMONTREAL	IFERC	Columbia Gulf		$2.7100		

Financial	Financial Swap		7/1/2015	3330748	Macquarie Bank Ltd	IFERC	Columbia Gulf	[redacted]	$2.7100	[redacted]		
Financial	Financial Swap		7/1/2015	3331414	Scotia Bank	IFERC	Columbia Gulf	[redacted]	$2.7100	[redacted]		
		7/1/2015 Total						[redacted]		[redacted]	21,620,600	[redacted]

Financial	Financial Option	Call	8/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub	[redacted]	$2.8860	[redacted]	
Financial	Financial Option	Put	8/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Call	8/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Put	8/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Call	8/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT		$2.8000		
Financial	Financial Option	Put	8/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT		$2.8000		
Financial	Financial Option	Call	8/1/2015	3227518	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.8900		
Financial	Financial Option	Put	8/1/2015	3227518	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.8900		
Financial	Financial Option	Call	8/1/2015	3227519	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Put	8/1/2015	3227519	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Call	8/1/2015	3227521	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Put	8/1/2015	3227521	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Call	8/1/2015	3227767	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.8600		
Financial	Financial Option	Put	8/1/2015	3227767	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.8600		
Financial	Financial Option	Call	8/1/2015	3238363	BKMONTREAL	IFERC	Henry Hub		$2.8900		
Financial	Financial Option	Put	8/1/2015	3238363	BKMONTREAL	IFERC	Henry Hub		$2.8900		
Financial	Financial Option	Call	8/1/2015	3246480	Citigroup Energy E	IFERC	Henry Hub		$2.8900		
Financial	Financial Option	Put	8/1/2015	3246480	Citigroup Energy E	IFERC	Henry Hub		$2.8900		
Financial	Financial Option	Call	8/1/2015	3251386	BKMONTREAL	IFERC	Henry Hub		$2.8900		
Financial	Financial Option	Put	8/1/2015	3251386	BKMONTREAL	IFERC	Henry Hub		$2.8900		
Financial	Financial Option	Call	8/1/2015	3264163	JPMorganChase Bank E	IFERC	Henry Hub		$2.8900		
Financial	Financial Option	Put	8/1/2015	3264163	JPMorganChase Bank E	IFERC	Henry Hub		$2.8900		
Financial	Financial Option	Call	8/1/2015	3266285	Morgan Stanley E	IFERC	Henry Hub		$2.8900		
Financial	Financial Option	Put	8/1/2015	3266285	Morgan Stanley E	IFERC	Henry Hub		$2.8900		
Financial	Financial Option	Call	8/1/2015	3279679	Citigroup Energy E	IFERC	Henry Hub		$2.8900		
Financial	Financial Option	Put	8/1/2015	3279679	Citigroup Energy E	IFERC	Henry Hub		$2.8900		
Financial	Financial Option	Call	8/1/2015	3292219	Citigroup Energy E	IFERC	Henry Hub		$2.8900		
Financial	Financial Option	Put	8/1/2015	3292219	Citigroup Energy E	IFERC	Henry Hub		$2.8900		
Financial	Financial Option	Call	8/1/2015	3298153	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Put	8/1/2015	3298153	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Call	8/1/2015	3301239	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Put	8/1/2015	3301239	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Call	8/1/2015	3304156	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Put	8/1/2015	3304156	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Call	8/1/2015	3310401	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Put	8/1/2015	3310401	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Call	8/1/2015	3312102	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Put	8/1/2015	3312102	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Call	8/1/2015	3317624	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Put	8/1/2015	3317624	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Call	8/1/2015	3321624	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Put	8/1/2015	3321624	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Call	8/1/2015	3327183	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Put	8/1/2015	3327183	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Call	8/1/2015	3328119	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Put	8/1/2015	3328119	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Call	8/1/2015	3332907	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Put	8/1/2015	3332907	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Call	8/1/2015	3334101	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.8600		
Financial	Financial Option	Put	8/1/2015	3334101	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.8600		
Financial	Financial Option	Call	8/1/2015	3336012	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.8600		
Financial	Financial Option	Put	8/1/2015	3336012	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.8600		
Financial	Financial Option	Call	8/1/2015	3336225	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Option	Put	8/1/2015	3336225	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.8860		
Financial	Financial Swap		8/1/2015	3223326	JPMorganChase Bank E	IFERC	Henry Hub		$2.8900		
Financial	Financial Swap		8/1/2015	3223331	JPMorganChase Bank E	IFERC	Henry Hub		$2.8900		
Financial	Financial Swap		8/1/2015	3223333	Morgan Stanley E	IFERC	Henry Hub		$2.8900		
Financial	Financial Swap		8/1/2015	3223336	Morgan Stanley E	IFERC	Henry Hub		$2.8900		
Financial	Financial Swap		8/1/2015	3223424	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.8900		
Financial	Financial Swap		8/1/2015	3223426	Macquarie Bank Ltd	IFERC	Henry Hub		$2.8900		
Financial	Financial Swap		8/1/2015	3223428	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.8900		
Financial	Financial Swap		8/1/2015	3223432	JPMorganChase Bank E	IFERC	Henry Hub		$2.8900		
Financial	Financial Swap		8/1/2015	3223434	Morgan Stanley E	IFERC	Henry Hub		$2.8900		
Financial	Financial Swap		8/1/2015	3223439	Morgan Stanley E	IFERC	Henry Hub		$2.8900		
Financial	Financial Swap		8/1/2015	3223475	Morgan Stanley E	IFERC	Henry Hub		$2.8900		
Financial	Financial Swap		8/1/2015	3223537	Morgan Stanley E	IFERC	Henry Hub		$2.8900		
Financial	Financial Swap		8/1/2015	3223541	Morgan Stanley E	IFERC	Henry Hub		$2.8900		

Financial	Financial Swap		8/1/2015	3223544	JPMorganChase Bank E	IFERC	Henry Hub	[redacted]	$2.8900	[redacted]		
Financial	Financial Swap		8/1/2015	3223546	Barclays Bank E	IFERC	Henry Hub		$2.8900			
Financial	Financial Swap		8/1/2015	3223547	JPMorganChase Bank E	IFERC	Henry Hub		$2.8900			
Financial	Financial Swap		8/1/2015	3223550	Morgan Stanley E	IFERC	Henry Hub		$2.8900			
Financial	Financial Swap		8/1/2015	3223552	Barclays Bank E	IFERC	Henry Hub		$2.8900			
Financial	Financial Swap		8/1/2015	3223567	Credit Suisse Intl	IFERC	Henry Hub		$2.8900			
Financial	Financial Swap		8/1/2015	3223569	Morgan Stanley E	IFERC	Henry Hub		$2.8900			
Financial	Financial Swap		8/1/2015	3223742	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.8860			
Financial	Financial Swap		8/1/2015	3223744	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.8860			
Financial	Financial Swap		8/1/2015	3224216	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.8860			
Financial	Financial Swap		8/1/2015	3224219	Credit Suisse Intl	NYMEX NG L1D	Henry Hub		$2.8860			
Financial	Financial Swap		8/1/2015	3224220	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8860			
Financial	Financial Swap		8/1/2015	3224229	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.8860			
Financial	Financial Swap		8/1/2015	3224232	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.8860			
Financial	Financial Swap		8/1/2015	3224245	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.8860			
Financial	Financial Swap		8/1/2015	3224252	Barclays Bank E	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224276	JPMorganChase Bank E	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224280	Barclays Bank E	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224337	Barclays Bank E	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224381	JPMorganChase Bank E	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224384	JPMorganChase Bank E	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224508	Morgan Stanley E	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224509	Morgan Stanley E	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224604	Credit Suisse Intl	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224618	JPMorganChase Bank E	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224620	Citigroup Energy E	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224621	JPMorganChase Bank E	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224640	Macquarie Bank Ltd	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224679	Barclays Bank E	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224681	JPMorganChase Bank E	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224682	Citigroup Energy E	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224683	JPMorganChase Bank E	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224684	MerrilL ynchCom E EM	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224693	JPMorganChase Bank E	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224697	Macquarie Bank Ltd	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224807	Credit Suisse Intl	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224813	MerrilL ynchCom E EM	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3224815	Credit Suisse Intl	IFERC	Transco Zone 4		$2.8600			
Financial	Financial Swap		8/1/2015	3224817	Barclays Bank E	IFERC	Transco Zone 4		$2.8600			
Financial	Financial Swap		8/1/2015	3224818	Morgan Stanley E	IFERC	Transco Zone 4		$2.8600			
Financial	Financial Swap		8/1/2015	3224826	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.8600			
Financial	Financial Swap		8/1/2015	3224914	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.8600			
Financial	Financial Swap		8/1/2015	3224915	Morgan Stanley E	IFERC	Transco Zone 4		$2.8600			
Financial	Financial Swap		8/1/2015	3224916	Morgan Stanley E	IFERC	Transco Zone 4		$2.8600			
Financial	Financial Swap		8/1/2015	3224919	Citigroup Energy E	IFERC	Transco Zone 4		$2.8600			
Financial	Financial Swap		8/1/2015	3224921	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.8600			
Financial	Financial Swap		8/1/2015	3224923	Credit Suisse Intl	IFERC	Transco Zone 4		$2.8600			
Financial	Financial Swap		8/1/2015	3224925	Citigroup Energy E	IFERC	Transco Zone 4		$2.8600			
Financial	Financial Swap		8/1/2015	3224927	Credit Suisse Intl	IFERC	Transco Zone 4		$2.8600			
Financial	Financial Swap		8/1/2015	3225044	Morgan Stanley E	IFERC	Transco Zone 4		$2.8600			
Financial	Financial Swap		8/1/2015	3225050	JPMorganChase Bank E	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3225057	MerrilL ynchCom E EM	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3225265	Morgan Stanley E	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3226557	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.8600			
Financial	Financial Swap		8/1/2015	3228840	BKMONTREAL	IFERC	Henry Hub		$2.8900			
Financial	Financial Swap		8/1/2015	3267250	JPMorganChase Bank E	IFERC	CGT		$2.8000			
Financial	Financial Swap		8/1/2015	3283784	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.8600			
Financial	Financial Swap		8/1/2015	3284453	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.8600			
Financial	Financial Swap		8/1/2015	3286344	Citigroup Energy E	IFERC	Transco Zone 4		$2.8600			
Financial	Financial Swap		8/1/2015	3294866	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.8600			
Financial	Financial Swap		8/1/2015	3297904	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8860			
Financial	Financial Swap		8/1/2015	3306466	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8860			
Financial	Financial Swap		8/1/2015	3307910	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.8860			
Financial	Financial Swap		8/1/2015	3321455	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$2.8860			
Financial	Financial Swap		8/1/2015	3322457	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.8860			
Financial	Financial Swap		8/1/2015	3323023	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.8600			
Financial	Financial Swap		8/1/2015	3324163	Citigroup Energy E	IFERC	Transco Zone 4		$2.8600			
Financial	Financial Swap		8/1/2015	3328730	BKMONTREAL	IFERC	Columbia Gulf		$2.8000			

Financial	Financial Swap		8/1/2015	3330748	Macquarie Bank Ltd	IFERC	Columbia Gulf	[redacted]	$2.8000	[redacted]		
Financial	Financial Swap		8/1/2015	3331414	Scotia Bank	IFERC	Columbia Gulf	[redacted]	$2.8000	[redacted]		
		8/1/2015 Total									22,922,000	[redacted]

Financial	Financial Option	Call	9/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub	[redacted]	$2.6380	[redacted]	
Financial	Financial Option	Put	9/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Call	9/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Put	9/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Call	9/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT		$2.5800		
Financial	Financial Option	Put	9/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT		$2.5800		
Financial	Financial Option	Call	9/1/2015	3227518	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.6400		
Financial	Financial Option	Put	9/1/2015	3227518	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.6400		
Financial	Financial Option	Call	9/1/2015	3227519	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Put	9/1/2015	3227519	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Call	9/1/2015	3227521	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Put	9/1/2015	3227521	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Call	9/1/2015	3227767	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.6300		
Financial	Financial Option	Put	9/1/2015	3227767	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.6300		
Financial	Financial Option	Call	9/1/2015	3238363	BKMONTREAL	IFERC	Henry Hub		$2.6400		
Financial	Financial Option	Put	9/1/2015	3238363	BKMONTREAL	IFERC	Henry Hub		$2.6400		
Financial	Financial Option	Call	9/1/2015	3246480	Citigroup Energy E	IFERC	Henry Hub		$2.6400		
Financial	Financial Option	Put	9/1/2015	3246480	Citigroup Energy E	IFERC	Henry Hub		$2.6400		
Financial	Financial Option	Call	9/1/2015	3251386	BKMONTREAL	IFERC	Henry Hub		$2.6400		
Financial	Financial Option	Put	9/1/2015	3251386	BKMONTREAL	IFERC	Henry Hub		$2.6400		
Financial	Financial Option	Call	9/1/2015	3264163	JPMorganChase Bank E	IFERC	Henry Hub		$2.6400		
Financial	Financial Option	Put	9/1/2015	3264163	JPMorganChase Bank E	IFERC	Henry Hub		$2.6400		
Financial	Financial Option	Call	9/1/2015	3266285	Morgan Stanley E	IFERC	Henry Hub		$2.6400		
Financial	Financial Option	Put	9/1/2015	3266285	Morgan Stanley E	IFERC	Henry Hub		$2.6400		
Financial	Financial Option	Call	9/1/2015	3279679	Citigroup Energy E	IFERC	Henry Hub		$2.6400		
Financial	Financial Option	Put	9/1/2015	3279679	Citigroup Energy E	IFERC	Henry Hub		$2.6400		
Financial	Financial Option	Call	9/1/2015	3292219	Citigroup Energy E	IFERC	Henry Hub		$2.6400		
Financial	Financial Option	Put	9/1/2015	3292219	Citigroup Energy E	IFERC	Henry Hub		$2.6400		
Financial	Financial Option	Call	9/1/2015	3298153	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Put	9/1/2015	3298153	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Call	9/1/2015	3301239	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Put	9/1/2015	3301239	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Call	9/1/2015	3304156	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Put	9/1/2015	3304156	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Call	9/1/2015	3310401	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Put	9/1/2015	3310401	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Call	9/1/2015	3312102	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Put	9/1/2015	3312102	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Call	9/1/2015	3317624	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Put	9/1/2015	3317624	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Call	9/1/2015	3321624	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Put	9/1/2015	3321624	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Call	9/1/2015	3327183	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Put	9/1/2015	3327183	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Call	9/1/2015	3328119	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Put	9/1/2015	3328119	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Call	9/1/2015	3332907	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Option	Put	9/1/2015	3332907	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.6380		
Financial	Financial Swap		9/1/2015	3223326	JPMorganChase Bank E	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		9/1/2015	3223331	JPMorganChase Bank E	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		9/1/2015	3223333	Morgan Stanley E	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		9/1/2015	3223336	Morgan Stanley E	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		9/1/2015	3223424	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		9/1/2015	3223426	Macquarie Bank Ltd	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		9/1/2015	3223428	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		9/1/2015	3223432	JPMorganChase Bank E	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		9/1/2015	3223434	Morgan Stanley E	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		9/1/2015	3223439	Morgan Stanley E	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		9/1/2015	3223475	Morgan Stanley E	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		9/1/2015	3223537	Morgan Stanley E	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		9/1/2015	3223541	Morgan Stanley E	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		9/1/2015	3223544	JPMorganChase Bank E	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		9/1/2015	3223546	Barclays Bank E	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		9/1/2015	3223547	JPMorganChase Bank E	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		9/1/2015	3223550	Morgan Stanley E	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		9/1/2015	3223552	Barclays Bank E	IFERC	Henry Hub		$2.6400		
Financial	Financial Swap		9/1/2015	3223567	Credit Suisse Intl	IFERC	Henry Hub		$2.6400		

Financial	Financial Swap		9/1/2015	3223569	Morgan Stanley E	IFERC	Henry Hub	[redacted]	$2.6400	[redacted]		
Financial	Financial Swap		9/1/2015	3223742	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.6380			
Financial	Financial Swap		9/1/2015	3223744	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.6380			
Financial	Financial Swap		9/1/2015	3224216	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.6380			
Financial	Financial Swap		9/1/2015	3224219	Credit Suisse Intl	NYMEX NG L1D	Henry Hub		$2.6380			
Financial	Financial Swap		9/1/2015	3224220	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6380			
Financial	Financial Swap		9/1/2015	3224229	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.6380			
Financial	Financial Swap		9/1/2015	3224232	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.6380			
Financial	Financial Swap		9/1/2015	3224245	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.6380			
Financial	Financial Swap		9/1/2015	3224252	Barclays Bank E	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224276	JPMorganChase Bank E	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224280	Barclays Bank E	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224337	Barclays Bank E	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224381	JPMorganChase Bank E	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224384	JPMorganChase Bank E	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224508	Morgan Stanley E	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224509	Morgan Stanley E	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224604	Credit Suisse Intl	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224618	JPMorganChase Bank E	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224620	Citigroup Energy E	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224621	JPMorganChase Bank E	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224640	Macquarie Bank Ltd	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224679	Barclays Bank E	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224681	JPMorganChase Bank E	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224682	Citigroup Energy E	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224683	JPMorganChase Bank E	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224684	MerrilL ynchCom E EM	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224693	JPMorganChase Bank E	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224697	Macquarie Bank Ltd	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224807	Credit Suisse Intl	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224813	MerrilL ynchCom E EM	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3224815	Credit Suisse Intl	IFERC	Transco Zone 4		$2.6300			
Financial	Financial Swap		9/1/2015	3224817	Barclays Bank E	IFERC	Transco Zone 4		$2.6300			
Financial	Financial Swap		9/1/2015	3224818	Morgan Stanley E	IFERC	Transco Zone 4		$2.6300			
Financial	Financial Swap		9/1/2015	3224826	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.6300			
Financial	Financial Swap		9/1/2015	3224914	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.6300			
Financial	Financial Swap		9/1/2015	3224915	Morgan Stanley E	IFERC	Transco Zone 4		$2.6300			
Financial	Financial Swap		9/1/2015	3224916	Morgan Stanley E	IFERC	Transco Zone 4		$2.6300			
Financial	Financial Swap		9/1/2015	3224919	Citigroup Energy E	IFERC	Transco Zone 4		$2.6300			
Financial	Financial Swap		9/1/2015	3224921	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.6300			
Financial	Financial Swap		9/1/2015	3224923	Credit Suisse Intl	IFERC	Transco Zone 4		$2.6300			
Financial	Financial Swap		9/1/2015	3224925	Citigroup Energy E	IFERC	Transco Zone 4		$2.6300			
Financial	Financial Swap		9/1/2015	3224927	Credit Suisse Intl	IFERC	Transco Zone 4		$2.6300			
Financial	Financial Swap		9/1/2015	3225044	Morgan Stanley E	IFERC	Transco Zone 4		$2.6300			
Financial	Financial Swap		9/1/2015	3225050	JPMorganChase Bank E	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3225057	MerrilL ynchCom E EM	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3225265	Morgan Stanley E	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3226557	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.6300			
Financial	Financial Swap		9/1/2015	3228840	BKMONTREAL	IFERC	Henry Hub		$2.6400			
Financial	Financial Swap		9/1/2015	3267250	JPMorganChase Bank E	IFERC	CGT		$2.5800			
Financial	Financial Swap		9/1/2015	3283784	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.6300			
Financial	Financial Swap		9/1/2015	3284453	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.6300			
Financial	Financial Swap		9/1/2015	3286344	Citigroup Energy E	IFERC	Transco Zone 4		$2.6300			
Financial	Financial Swap		9/1/2015	3294866	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.6300			
Financial	Financial Swap		9/1/2015	3297904	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6380			
Financial	Financial Swap		9/1/2015	3306466	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6380			
Financial	Financial Swap		9/1/2015	3307910	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.6380			
Financial	Financial Swap		9/1/2015	3321455	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$2.6380			
Financial	Financial Swap		9/1/2015	3322457	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.6380			
Financial	Financial Swap		9/1/2015	3323023	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.6300			
Financial	Financial Swap		9/1/2015	3324163	Citigroup Energy E	IFERC	Transco Zone 4		$2.6300			
Financial	Financial Swap		9/1/2015	3330748	Macquarie Bank Ltd	IFERC	Columbia Gulf		$2.5800			
Financial	Financial Swap		9/1/2015	3331414	Scotia Bank	IFERC	Columbia Gulf		$2.5800			
		9/1/2015 Total						[redacted]		[redacted]	20,033,700	[redacted]

Financial	Financial Option	Call	10/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub	[redacted]	$2.5630	[redacted]	
Financial	Financial Option	Put	10/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Option	Call	10/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Option	Put	10/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Option	Call	10/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT		$2.4700		
Financial	Financial Option	Put	10/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT		$2.4700		
Financial	Financial Option	Call	10/1/2015	3227519	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Option	Put	10/1/2015	3227519	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Option	Call	10/1/2015	3227521	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Option	Put	10/1/2015	3227521	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Option	Call	10/1/2015	3227767	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.5300		
Financial	Financial Option	Put	10/1/2015	3227767	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.5300		
Financial	Financial Option	Call	10/1/2015	3321624	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Option	Put	10/1/2015	3321624	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Option	Call	10/1/2015	3327183	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Option	Put	10/1/2015	3327183	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Option	Call	10/1/2015	3328119	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Option	Put	10/1/2015	3328119	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Option	Call	10/1/2015	3332907	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Option	Put	10/1/2015	3332907	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Swap		10/1/2015	3223326	JPMorganChase Bank E	IFERC	Henry Hub		$2.5600		
Financial	Financial Swap		10/1/2015	3223331	JPMorganChase Bank E	IFERC	Henry Hub		$2.5600		
Financial	Financial Swap		10/1/2015	3223333	Morgan Stanley E	IFERC	Henry Hub		$2.5600		
Financial	Financial Swap		10/1/2015	3223336	Morgan Stanley E	IFERC	Henry Hub		$2.5600		
Financial	Financial Swap		10/1/2015	3223424	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.5600		
Financial	Financial Swap		10/1/2015	3223426	Macquarie Bank Ltd	IFERC	Henry Hub		$2.5600		
Financial	Financial Swap		10/1/2015	3223428	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.5600		
Financial	Financial Swap		10/1/2015	3223432	JPMorganChase Bank E	IFERC	Henry Hub		$2.5600		
Financial	Financial Swap		10/1/2015	3223434	Morgan Stanley E	IFERC	Henry Hub		$2.5600		
Financial	Financial Swap		10/1/2015	3223439	Morgan Stanley E	IFERC	Henry Hub		$2.5600		
Financial	Financial Swap		10/1/2015	3223475	Morgan Stanley E	IFERC	Henry Hub		$2.5600		
Financial	Financial Swap		10/1/2015	3223537	Morgan Stanley E	IFERC	Henry Hub		$2.5600		
Financial	Financial Swap		10/1/2015	3223541	Morgan Stanley E	IFERC	Henry Hub		$2.5600		
Financial	Financial Swap		10/1/2015	3223544	JPMorganChase Bank E	IFERC	Henry Hub		$2.5600		
Financial	Financial Swap		10/1/2015	3223546	Barclays Bank E	IFERC	Henry Hub		$2.5600		
Financial	Financial Swap		10/1/2015	3223547	JPMorganChase Bank E	IFERC	Henry Hub		$2.5600		
Financial	Financial Swap		10/1/2015	3223550	Morgan Stanley E	IFERC	Henry Hub		$2.5600		
Financial	Financial Swap		10/1/2015	3223552	Barclays Bank E	IFERC	Henry Hub		$2.5600		
Financial	Financial Swap		10/1/2015	3223567	Credit Suisse Intl	IFERC	Henry Hub		$2.5600		
Financial	Financial Swap		10/1/2015	3223569	Morgan Stanley E	IFERC	Henry Hub		$2.5600		
Financial	Financial Swap		10/1/2015	3223742	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Swap		10/1/2015	3223744	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Swap		10/1/2015	3224216	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Swap		10/1/2015	3224219	Credit Suisse Intl	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Swap		10/1/2015	3224220	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Swap		10/1/2015	3224229	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Swap		10/1/2015	3224232	Barclays Bank E	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Swap		10/1/2015	3224245	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.5630		
Financial	Financial Swap		10/1/2015	3224252	Barclays Bank E	IFERC	CGT		$2.4700		
Financial	Financial Swap		10/1/2015	3224276	JPMorganChase Bank E	IFERC	CGT		$2.4700		
Financial	Financial Swap		10/1/2015	3224280	Barclays Bank E	IFERC	CGT		$2.4700		
Financial	Financial Swap		10/1/2015	3224337	Barclays Bank E	IFERC	CGT		$2.4700		
Financial	Financial Swap		10/1/2015	3224381	JPMorganChase Bank E	IFERC	CGT		$2.4700		
Financial	Financial Swap		10/1/2015	3224384	JPMorganChase Bank E	IFERC	CGT		$2.4700		
Financial	Financial Swap		10/1/2015	3224508	Morgan Stanley E	IFERC	CGT		$2.4700		
Financial	Financial Swap		10/1/2015	3224509	Morgan Stanley E	IFERC	CGT		$2.4700		
Financial	Financial Swap		10/1/2015	3224604	Credit Suisse Intl	IFERC	CGT		$2.4700		
Financial	Financial Swap		10/1/2015	3224618	JPMorganChase Bank E	IFERC	CGT		$2.4700		
Financial	Financial Swap		10/1/2015	3224620	Citigroup Energy E	IFERC	CGT		$2.4700		
Financial	Financial Swap		10/1/2015	3224621	JPMorganChase Bank E	IFERC	CGT		$2.4700		
Financial	Financial Swap		10/1/2015	3224640	Macquarie Bank Ltd	IFERC	CGT		$2.4700		
Financial	Financial Swap		10/1/2015	3224679	Barclays Bank E	IFERC	CGT		$2.4700		
Financial	Financial Swap		10/1/2015	3224681	JPMorganChase Bank E	IFERC	CGT		$2.4700		
Financial	Financial Swap		10/1/2015	3224682	Citigroup Energy E	IFERC	CGT		$2.4700		
Financial	Financial Swap		10/1/2015	3224683	JPMorganChase Bank E	IFERC	CGT		$2.4700		
Financial	Financial Swap		10/1/2015	3224684	MerrilL ynchCom E EM	IFERC	CGT		$2.4700		
Financial	Financial Swap		10/1/2015	3224693	JPMorganChase Bank E	IFERC	CGT		$2.4700		

Financial	Financial Swap		10/1/2015	3224697	Macquarie Bank Ltd	IFERC	CGT	[redacted]	$2.4700	[redacted]		
Financial	Financial Swap		10/1/2015	3224807	Credit Suisse Intl	IFERC	CGT		$2.4700			
Financial	Financial Swap		10/1/2015	3224813	MerrilL ynchCom E EM	IFERC	CGT		$2.4700			
Financial	Financial Swap		10/1/2015	3224815	Credit Suisse Intl	IFERC	Transco Zone 4		$2.5300			
Financial	Financial Swap		10/1/2015	3224817	Barclays Bank E	IFERC	Transco Zone 4		$2.5300			
Financial	Financial Swap		10/1/2015	3224818	Morgan Stanley E	IFERC	Transco Zone 4		$2.5300			
Financial	Financial Swap		10/1/2015	3224826	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.5300			
Financial	Financial Swap		10/1/2015	3224914	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.5300			
Financial	Financial Swap		10/1/2015	3224915	Morgan Stanley E	IFERC	Transco Zone 4		$2.5300			
Financial	Financial Swap		10/1/2015	3224916	Morgan Stanley E	IFERC	Transco Zone 4		$2.5300			
Financial	Financial Swap		10/1/2015	3224919	Citigroup Energy E	IFERC	Transco Zone 4		$2.5300			
Financial	Financial Swap		10/1/2015	3224921	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.5300			
Financial	Financial Swap		10/1/2015	3224923	Credit Suisse Intl	IFERC	Transco Zone 4		$2.5300			
Financial	Financial Swap		10/1/2015	3224925	Citigroup Energy E	IFERC	Transco Zone 4		$2.5300			
Financial	Financial Swap		10/1/2015	3224927	Credit Suisse Intl	IFERC	Transco Zone 4		$2.5300			
Financial	Financial Swap		10/1/2015	3225044	Morgan Stanley E	IFERC	Transco Zone 4		$2.5300			
Financial	Financial Swap		10/1/2015	3225050	JPMorganChase Bank E	IFERC	CGT		$2.4700			
Financial	Financial Swap		10/1/2015	3225057	MerrilL ynchCom E EM	IFERC	CGT		$2.4700			
Financial	Financial Swap		10/1/2015	3225265	Morgan Stanley E	IFERC	CGT		$2.4700			
Financial	Financial Swap		10/1/2015	3226557	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.5300			
Financial	Financial Swap		10/1/2015	3267250	JPMorganChase Bank E	IFERC	CGT		$2.4700			
Financial	Financial Swap		10/1/2015	3283784	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.5300			
Financial	Financial Swap		10/1/2015	3284453	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.5300			
Financial	Financial Swap		10/1/2015	3286344	Citigroup Energy E	IFERC	Transco Zone 4		$2.5300			
Financial	Financial Swap		10/1/2015	3294866	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.5300			
Financial	Financial Swap		10/1/2015	3306466	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.5630			
Financial	Financial Swap		10/1/2015	3322457	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.5630			
Financial	Financial Swap		10/1/2015	3323023	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.5300			
Financial	Financial Swap		10/1/2015	3324163	Citigroup Energy E	IFERC	Transco Zone 4		$2.5300			
Financial	Financial Swap		10/1/2015	3330748	Macquarie Bank Ltd	IFERC	Columbia Gulf		$2.4700			
Financial	Financial Swap		10/1/2015	3331414	Scotia Bank	IFERC	Columbia Gulf		$2.4700			
		10/1/2015 Total									17,807,100	[redacted]

Financial	Financial Option	Call	11/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub	[redacted]	$2.0330	[redacted]	
Financial	Financial Option	Put	11/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.0330		
Financial	Financial Option	Call	11/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.0330		
Financial	Financial Option	Put	11/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.0330		
Financial	Financial Option	Call	11/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT		$1.9400		
Financial	Financial Option	Put	11/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT		$1.9400		
Financial	Financial Option	Call	11/1/2015	3328129	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.0330		
Financial	Financial Option	Put	11/1/2015	3328129	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.0330		
Financial	Financial Option	Call	11/1/2015	3347636	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.0330		
Financial	Financial Option	Put	11/1/2015	3347636	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.0330		
Financial	Financial Option	Call	11/1/2015	3348334	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.0330		
Financial	Financial Option	Put	11/1/2015	3348334	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.0330		
Financial	Financial Option	Call	11/1/2015	3352226	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.0330		
Financial	Financial Option	Put	11/1/2015	3352226	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.0330		
Financial	Financial Option	Call	11/1/2015	3354168	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.0330		
Financial	Financial Option	Put	11/1/2015	3354168	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.0330		
Financial	Financial Swap		11/1/2015	3223428	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.0300		
Financial	Financial Swap		11/1/2015	3223434	Morgan Stanley E	IFERC	Henry Hub		$2.0300		
Financial	Financial Swap		11/1/2015	3223439	Morgan Stanley E	IFERC	Henry Hub		$2.0300		
Financial	Financial Swap		11/1/2015	3223546	Barclays Bank E	IFERC	Henry Hub		$2.0300		
Financial	Financial Swap		11/1/2015	3223547	JPMorganChase Bank E	IFERC	Henry Hub		$2.0300		
Financial	Financial Swap		11/1/2015	3224926	Morgan Stanley E	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3224928	MerrilL ynchCom E EM	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3224929	MerrilL ynchCom E EM	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3225039	Morgan Stanley E	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3225040	JPMorganChase Bank E	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3225041	MerrilL ynchCom E EM	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3225042	Morgan Stanley E	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3225043	Citigroup Energy E	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3225046	Morgan Stanley E	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3225047	JPMorganChase Bank E	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3225056	JPMorganChase Bank E	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3225060	Macquarie Bank Ltd	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3225068	Citigroup Energy E	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3225069	Citigroup Energy E	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3225071	Morgan Stanley E	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3225088	BKMONTREAL	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3225107	JPMorganChase Bank E	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3225120	Morgan Stanley E	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3225202	BKMONTREAL	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3225203	JPMorganChase Bank E	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3225285	Macquarie Bank Ltd	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3226328	JPMorganChase Bank E	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3226334	JPMorganChase Bank E	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3226373	BKMONTREAL	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3226378	BKMONTREAL	IFERC	Transco Zone 4		$2.0200		
Financial	Financial Swap		11/1/2015	3226447	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.0200		
Financial	Financial Swap		11/1/2015	3226554	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.0200		
Financial	Financial Swap		11/1/2015	3226563	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.0200		
Financial	Financial Swap		11/1/2015	3226566	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.0200		
Financial	Financial Swap		11/1/2015	3226569	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.0200		
Financial	Financial Swap		11/1/2015	3226754	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.0200		
Financial	Financial Swap		11/1/2015	3226790	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.0200		
Financial	Financial Swap		11/1/2015	3226796	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.0300		
Financial	Financial Swap		11/1/2015	3226801	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.0200		
Financial	Financial Swap		11/1/2015	3226803	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.0200		
Financial	Financial Swap		11/1/2015	3238365	Citigroup Energy E	IFERC	Henry Hub		$2.0300		
Financial	Financial Swap		11/1/2015	3240195	BKMONTREAL	IFERC	Henry Hub		$2.0300		
Financial	Financial Swap		11/1/2015	3243801	BKMONTREAL	IFERC	Henry Hub		$2.0300		
Financial	Financial Swap		11/1/2015	3251815	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.0200		
Financial	Financial Swap		11/1/2015	3257541	Citigroup Energy E	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3269357	JPMorganChase Bank E	IFERC	CGT		$1.9400		
Financial	Financial Swap		11/1/2015	3286345	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.0330		
Financial	Financial Swap		11/1/2015	3294865	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.0330		
Financial	Financial Swap		11/1/2015	3297902	BNP Paribas E,EM	IFERC	Transco Zone 4		$2.0200		
Financial	Financial Swap		11/1/2015	3301240	BNP Paribas E,EM	IFERC	Transco Zone 4		$2.0200		
Financial	Financial Swap		11/1/2015	3306467	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.0330		

Financial	Financial Swap		11/1/2015	3307909	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub	[redacted]	$2.0330	[redacted]		
Financial	Financial Swap		11/1/2015	3310403	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.0200			
Financial	Financial Swap		11/1/2015	3312109	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.0200			
Financial	Financial Swap		11/1/2015	3317625	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.0200			
Financial	Financial Swap		11/1/2015	3321456	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$2.0330			
Financial	Financial Swap		11/1/2015	3322458	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.0330			
Financial	Financial Swap		11/1/2015	3323024	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.0200			
Financial	Financial Swap		11/1/2015	3324164	Morgan Stanley E	IFERC	Transco Zone 4		$2.0200			
Financial	Financial Swap		11/1/2015	3330749	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$1.9400			
Financial	Financial Swap		11/1/2015	3356603	BKMONTREAL	IFERC	Transco Zone 4		$2.0200			
		11/1/2015 Total						[redacted]		[redacted]	18,705,400	[redacted]

Financial	Financial Option	Call	12/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub	[redacted]	$2.2060	[redacted]	
Financial	Financial Option	Put	12/1/2015	3227307	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.2060		
Financial	Financial Option	Call	12/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.2060		
Financial	Financial Option	Put	12/1/2015	3227311	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.2060		
Financial	Financial Option	Call	12/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT		$2.1200		
Financial	Financial Option	Put	12/1/2015	3227312	JPMorganChase Bank E	IFERC	CGT		$2.1200		
Financial	Financial Option	Call	12/1/2015	3328129	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.2060		
Financial	Financial Option	Put	12/1/2015	3328129	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.2060		
Financial	Financial Option	Call	12/1/2015	3347636	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.2060		
Financial	Financial Option	Put	12/1/2015	3347636	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.2060		
Financial	Financial Option	Call	12/1/2015	3348334	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.2060		
Financial	Financial Option	Put	12/1/2015	3348334	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.2060		
Financial	Financial Option	Call	12/1/2015	3352226	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.2060		
Financial	Financial Option	Put	12/1/2015	3352226	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.2060		
Financial	Financial Option	Call	12/1/2015	3354168	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.2060		
Financial	Financial Option	Put	12/1/2015	3354168	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.2060		
Financial	Financial Swap		12/1/2015	3223428	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.2100		
Financial	Financial Swap		12/1/2015	3223434	Morgan Stanley E	IFERC	Henry Hub		$2.2100		
Financial	Financial Swap		12/1/2015	3223439	Morgan Stanley E	IFERC	Henry Hub		$2.2100		
Financial	Financial Swap		12/1/2015	3223546	Barclays Bank E	IFERC	Henry Hub		$2.2100		
Financial	Financial Swap		12/1/2015	3223547	JPMorganChase Bank E	IFERC	Henry Hub		$2.2100		
Financial	Financial Swap		12/1/2015	3224926	Morgan Stanley E	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3224928	MerrilL ynchCom E EM	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3224929	MerrilL ynchCom E EM	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3225039	Morgan Stanley E	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3225040	JPMorganChase Bank E	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3225041	MerrilL ynchCom E EM	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3225042	Morgan Stanley E	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3225043	Citigroup Energy E	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3225046	Morgan Stanley E	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3225047	JPMorganChase Bank E	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3225056	JPMorganChase Bank E	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3225060	Macquarie Bank Ltd	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3225068	Citigroup Energy E	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3225069	Citigroup Energy E	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3225071	Morgan Stanley E	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3225088	BKMONTREAL	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3225107	JPMorganChase Bank E	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3225120	Morgan Stanley E	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3225202	BKMONTREAL	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3225203	JPMorganChase Bank E	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3225285	Macquarie Bank Ltd	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3226328	JPMorganChase Bank E	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3226334	JPMorganChase Bank E	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3226373	BKMONTREAL	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3226378	BKMONTREAL	IFERC	Transco Zone 4		$2.2200		
Financial	Financial Swap		12/1/2015	3226447	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.2200		
Financial	Financial Swap		12/1/2015	3226554	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.2200		
Financial	Financial Swap		12/1/2015	3226563	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.2200		
Financial	Financial Swap		12/1/2015	3226566	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.2200		
Financial	Financial Swap		12/1/2015	3226569	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.2200		
Financial	Financial Swap		12/1/2015	3226754	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.2200		
Financial	Financial Swap		12/1/2015	3226790	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.2200		
Financial	Financial Swap		12/1/2015	3226796	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.2100		
Financial	Financial Swap		12/1/2015	3226801	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.2200		
Financial	Financial Swap		12/1/2015	3226803	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.2200		
Financial	Financial Swap		12/1/2015	3238365	Citigroup Energy E	IFERC	Henry Hub		$2.2100		
Financial	Financial Swap		12/1/2015	3240195	BKMONTREAL	IFERC	Henry Hub		$2.2100		
Financial	Financial Swap		12/1/2015	3243801	BKMONTREAL	IFERC	Henry Hub		$2.2100		
Financial	Financial Swap		12/1/2015	3251815	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.2200		
Financial	Financial Swap		12/1/2015	3257541	Citigroup Energy E	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3269357	JPMorganChase Bank E	IFERC	CGT		$2.1200		
Financial	Financial Swap		12/1/2015	3286345	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.2060		
Financial	Financial Swap		12/1/2015	3294865	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.2060		
Financial	Financial Swap		12/1/2015	3297902	BNP Paribas E,EM	IFERC	Transco Zone 4		$2.2200		
Financial	Financial Swap		12/1/2015	3301240	BNP Paribas E,EM	IFERC	Transco Zone 4		$2.2200		
Financial	Financial Swap		12/1/2015	3306467	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.2060		

Financial	Financial Swap		12/1/2015	3307909	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub	[redacted]	$2.2060	[redacted]		
Financial	Financial Swap		12/1/2015	3310403	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.2200			
Financial	Financial Swap		12/1/2015	3312109	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.2200			
Financial	Financial Swap		12/1/2015	3317625	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.2200			
Financial	Financial Swap		12/1/2015	3321456	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$2.2060			
Financial	Financial Swap		12/1/2015	3322458	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.2060			
Financial	Financial Swap		12/1/2015	3323024	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.2200			
Financial	Financial Swap		12/1/2015	3324164	Morgan Stanley E	IFERC	Transco Zone 4		$2.2200			
Financial	Financial Swap		12/1/2015	3330749	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$2.1200			
Financial	Financial Swap		12/1/2015	3356603	BKMONTREAL	IFERC	Transco Zone 4		$2.2200			
		12/1/2015 Total						[redacted]		[redacted]	19,176,900	[redacted]

As of December 31, 2015

DEF Gas Storage Hedging Status
REDACTED

Physical/ Financial	Instrument	Month	Trade Number	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Injection	% Hedged
Financial	FIXED SWAP	6/1/2015	3312108	BNP Paribas E,EM	IFERC	FGTZ3	[redacted]	[redacted]	$2.8500	[redacted]		
Financial	FIXED SWAP	6/1/2015	3323620	JPMorganChase Bank E	IFERC	FGTZ3			$2.8500			
		6/1/2015 Total					150,000			$15,375	250,000	60%

As of December 31, 2015

DEF #2 Oil Hedging Status
REDACTED

Physical/ Financial	Instrument	Month	Trade Number	Counterparty	Market	Location	Volume (Gallon)	Fixed Price ($/Gallon)	Market Scan Biz Average ($/Gallon)	Savings/Cost on Hedge	Actual/Projected Burns	% Hedged
Financial	FIXED SWAP	1/1/2015	3280065	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.5378			
		1/1/2015 Total									410,276	
Financial	FIXED SWAP	2/1/2015	3280065	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.8127			
		2/1/2015 Total									1,364,045	
Financial	FIXED SWAP	3/1/2015	3280065	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.7100			
		3/1/2015 Total									221,413	
Financial	FIXED SWAP	4/1/2015	3280065	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.7771			
		4/1/2015 Total									375,413	
Financial	FIXED SWAP	5/1/2015	3292934	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.9176			
		5/1/2015 Total									384,011	
Financial	FIXED SWAP	6/1/2015	3280065	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.8016			
		6/1/2015 Total									317,903	
Financial	FIXED SWAP	7/1/2015	3280065	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.6184			
		7/1/2015 Total									271,189	
Financial	FIXED SWAP	8/1/2015	3280065	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.4614			
		8/1/2015 Total									591,941	
Financial	FIXED SWAP	9/1/2015	3280065	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.4423			
		9/1/2015 Total									567,384	
Financial	FIXED SWAP	10/1/2015	3280065	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.4186			
		10/1/2015 Total									294,697	
Financial	FIXED SWAP	11/1/2015	3280065	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.3584			
		11/1/2015 Total									1,815,016	
Financial	FIXED SWAP	12/1/2015	3280065	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.0915			
		12/1/2015 Total									312,713	

DEF Coal Transportation Hedging Status - Barge
REDACTED

As of December 31, 2015

Physical/ Financial	Instrument	Month	Trade Number	Counterparty	Market	Location	Volume (Gallons)	Fixed Price ($/Gallons)	Market Settlement ($/Gallons)	Estimated Savings/(Cost) on Hedge	Estimated Exposure	Total % Estimated Hedged Exposure
Financial	FIXED SWAP	1/1/2015	3283754	Macquarie Bank Ltd	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.5378			
Financial	FIXED SWAP	1/1/2015	3284226	Morgan Stanley E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.5378			
		1/1/2015 Total									583,589	
Financial	FIXED SWAP	2/1/2015	3283754	Macquarie Bank Ltd	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.8127			
Financial	FIXED SWAP	2/1/2015	3284226	Morgan Stanley E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.8127			
		2/1/2015 Total									573,940	
Financial	FIXED SWAP	3/1/2015	3283754	Macquarie Bank Ltd	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.7100			
Financial	FIXED SWAP	3/1/2015	3284226	Morgan Stanley E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.7100			
		3/1/2015 Total									570,206	
Financial	FIXED SWAP	4/1/4015	3284226	Morgan Stanley E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.7771			
Financial	FIXED SWAP	4/1/2015	3288977	BP Energy Co E,EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.7771			
		4/1/2015 Total									537,905	
Financial	FIXED SWAP	5/1/2015	3284226	Morgan Stanley E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.9176			
Financial	FIXED SWAP	5/1/2015	3288977	BP Energy Co E,EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.9176			
		5/1/2015 Total									522,687	
Financial	FIXED SWAP	6/1/2015	3284226	Morgan Stanley E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.8016			
Financial	FIXED SWAP	6/1/2015	3288977	BP Energy Co E,EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.8016			
		6/1/2015 Total									517,576	
Financial	FIXED SWAP	7/1/2015	3288977	BP Energy Co E,EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.6184			
Financial	FIXED SWAP	7/1/2015	3288978	BP Energy Co E,EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.6184			
		7/1/2015 Total									530,616	
Financial	FIXED SWAP	8/1/2015	3288977	BP Energy Co E,EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.4614			
Financial	FIXED SWAP	8/1/2015	3288978	BP Energy Co E,EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.4614			
		8/1/2015 Total									524,103	
Financial	FIXED SWAP	9/1/2015	3288977	BP Energy Co E,EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.4423			
Financial	FIXED SWAP	9/1/2015	3288978	BP Energy Co E,EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.4423			
		9/1/2015 Total									517,631	
Financial	FIXED SWAP	10/1/2015	3297786	Macquarie Bank Ltd	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.4186			
		10/1/2015 Total									359,213	
Financial	FIXED SWAP	11/1/2015	3297786	Macquarie Bank Ltd	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.3584			
		11/1/2015 Total									361,686	
Financial	FIXED SWAP	12/1/2015	3311032	Macquarie Bank Ltd	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.0915			
		12/1/2015 Total									432,284	

DEF Coal Transportation Hedging Status - Rail
REDACTED

As of December 31, 2015

Physical/ Financial	Instrument	Month	Trade Number	Counterparty	Market	Location	Volume (Gallons)	Fixed Price ($/Gallons)	Market Settlement ($/Gallons)	Estimated Savings/(Cost) on Hedge	Estimated Exposure	Total % Estimated Hedged Exposure
Financial	FIXED SWAP	1/1/2015	3288578	MerrilL ynchCom E EM	Gulfcoast Pipe ULSG	Gulf Coast Pipeline			$1.5378			
		1/1/2015 Total									108,481	
Financial	FIXED SWAP	2/1/2015	3288578	MerrilL ynchCom E EM	Gulfcoast Pipe ULSG	Gulf Coast Pipeline			$1.8127			
		2/1/2015 Total									100,994	
Financial	FIXED SWAP	3/1/2015	3288578	MerrilL ynchCom E EM	Gulfcoast Pipe ULSG	Gulf Coast Pipeline			$1.7100			
		3/1/2015 Total									100,994	
Financial	FIXED SWAP	4/1/2015	3288969	BP Energy Co E,EM	Gulfcoast Pipe ULSG	Gulf Coast Pipeline			$1.7771			
		4/1/2015 Total									100,994	
Financial	FIXED SWAP	5/1/2015	3288969	BP Energy Co E,EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.9176			
		5/1/2015 Total									141,075	
Financial	FIXED SWAP	6/1/2015	3288969	BP Energy Co E,EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.8016			
		6/1/2015 Total									125,400	
Financial	FIXED SWAP	7/1/2015	3329255	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.6184			
		7/1/2015 Total									141,075	
Financial	FIXED SWAP	8/1/2015	3329255	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.4614			
		8/1/2015 Total									141,075	
Financial	FIXED SWAP	9/1/2015	3329255	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.4423			
		9/1/2015 Total									125,400	

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Duke Energy Florida
Docket No. 160001-EI
Witness: McCallister
Exhibit JM-2T

As of January 2015 - Forecasted Light Oil Hedge Percentage

#2 Oil Barrels	Forecasted Burns	Hedged Volume	% Hedge
January-15	2,971		
February-15	1,196		
March-15	1,247		
April-15	1,578		
May-15	2,255		
June-15	2,980		
July-15	3,190		
August-15	2,566		
September-15	1,444		
October-15	1,152		
November-15	3,431		
December-15	2,533		
	26,541		

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 9
PARTY: DUKE ENERGY FLORIDA, LLC – (DIRECT)
DESCRIPTION: Joseph McCallister JM-2T

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Duke Energy Florida, LLC
Risk Management Plan for
Fuel Procurement and Wholesale Power Purchases
For 2017

Duke Energy Florida, LLC (DEF) is submitting its 2017 Risk Management Plan (Plan) for review by the Florida Public Service Commission (FPSC). The Plan includes the required items as outlined in Attachment A of Order No. PSC-02-1484-FOF-EI and specifically items 1 through 9, and items 13 through 15 as set forth in Exhibit TFB-4 to the prefiled testimony of Todd F. Bohrmann in Docket No. 011605-EI and further clarified in Order No. PSC-08-0667-PAA-EI of Docket No. 080001-EI.

Several groups play key roles in the management, monitoring, and execution of the activities outlined in DEF's Plan. These groups include Fuels and System Optimization (FSO), Global Risk Management (GRM), which includes Enterprise and Regulated Risk Management, Regulated Accounting, Internal Audit, Legal, and Information Technology. The activities supported by these groups include procuring competitively priced fuel, performing active asset optimization and portfolio management, executing DEF's approved hedging strategy, monitoring and reporting against established oversight limits for credit and margin limits, performing credit evaluations and monitoring credit and default exposure, performing deal validation, volume actualization, preparing and reviewing transactions and contracts, preparing journal entries to account for fuel and power related activities, performing billing and payments under the various fuel and purchased power contracts, performing audits, and maintaining and supporting needed systems to capture, track, and account for these activities.

Based on the Summer 2016 Fuels and Operations Forecast (FOF), DEF's estimated fuel consumption and economy power transactions projections for 2017 are as follows:

Coal

Based on current projections, DEF forecasts to burn approximately [redacted] tons of coal in 2017. DEF's forecasted coal requirements for 2017 will primarily be purchased under term coal supply agreements. Currently the coal supply will be delivered to DEF's plants via barge and rail transportation agreements as needed Spot purchases will be made as needed to supplement the term purchases.

Light Oil

Based on current projections, DEF forecasts to burn approximately [redacted] barrels of light oil in 2017. DEF's forecasted light fuel oil requirements for 2017 are expected to be purchased primarily under term supply

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 10
PARTY: DUKE ENERGY FLORIDA, LLC – (DIRECT)
DESCRIPTION: Joseph McCallister JM-1P

agreements with volume flexibility at indexed market prices. Spot market purchases will be made as needed to supplement term purchases.

Natural Gas

Based on current projections, DEF forecasts to burn approximately [redacted] of natural gas in 2017, comprised of approximately [redacted] at DEF's generating plants and [redacted] at gas-tolling purchased power facilities where DEF has the responsibility to provide the natural gas. DEF's forecasted natural gas requirements for 2017 are expected to be purchased primarily under term supply agreements based on market index pricing, with supplemental seasonal, monthly and daily purchases of natural gas being made as needed.

Economy Power Purchases and Sales

Based on current projections, DEF forecasts to purchase approximately [redacted] of economy power and sell approximately [redacted] of economy power in 2017. DEF actively seeks to purchase and sell economy power as opportunities arise based on market prices, dispatch costs, and available transmission capacity.

Item 1. Identify the company's overall quantitative and qualitative Risk Management Plan Objectives.

DEF's identified Plan Objectives are to effectively manage its overall fuel and purchased power costs for its customers by engaging in competitive fuel procurement practices and activities, performing active asset optimization and portfolio management activities, and continuing to execute the Company's hedging program to reduce price risk and volatility, and provide greater fuel cost certainty for DEF's customers. These items are discussed further in Item 8.

Item 2. Identify the minimum quantity of fuel to be hedged and the activities to be executed for the balance of 2016 and 2017.

DEF utilizes a phased hedging program where financial hedge transactions are executed over time with the objectives of reducing price risk and volatility and providing greater fuel cost certainty for DEF's customers. The financial hedging program outlined in this Plan includes executing approved financial agreements over time for natural gas exposures. Natural gas hedging activity represents the largest component of DEF's hedging program as natural gas represents the largest fuel cost component of DEF's overall generation fuel costs.

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The volumes hedged over time for natural gas represent a portion of DEF's forecasted burns with higher hedging target ranges in the near term and lower hedging target ranges in the outer period. The hedge percentage target ranges outlined provide a framework for consistently executing the layered hedging strategy over time. DEF currently uses two types of financial transactions to hedge which are swaps and costless collars. DEF cannot predict future prices and DEF's hedging program does not involve speculation or trying to "out-guess" the market. All hedges are executed at the prevailing market price for any given period that exists at the time the financial hedging transactions are executed. The results of the hedging activities may or may not result in net fuel cost savings due to differences between the monthly settlement prices and the actual hedge price of the transactions that were executed over time. The volumes hedged for each fuel type over time are based on periodic updated fuel forecasts and the actual hedge percentages for any month, rolling period, or calendar annual period may come in higher or lower than the target hedge percentages and hedging ranges because of actual fuel burns versus forecasted fuel burns. Actual burns can deviate from forecasted burns because of dynamic variables such as weather, unforeseen unit outages, actual load, and changing fuel prices. DEF's multi-year approach to executing fixed price transactions over time is a reasonable and prudent approach to reduce price risk and volatility and provide greater fuel cost certainty for DEF's customers.

Outlined below for each fuel type and exposure are the minimum and maximum ranges and targeted hedge percentages to be hedged during the remainder of 2016 and during 2017:

<u>Natural Gas</u>
Natural gas represents DEF's largest fuel cost component and represents the largest component of DEF's hedging activities. DEF plans to continue to execute its existing phased financial hedging program over a rolling 36-month time period through time for natural gas through the remainder of 2016 and during 2017 within the following hedge percentage ranges:

- 1 to 12 months – [redacted] with an approximate target of [redacted];
- 13 to 24 months [redacted] with an approximate target of [redacted];
- 25 to 36 months – [redacted] with an approximate target of [redacted].

For calendar year 2017, DEF will target to hedge approximately [redacted] of forecasted natural gas burn. The above hedging ranges and approximate target percentages represent reductions from both the 2016 Risk Management Plan and those filed with the Joint Hedging Petition Filed by the Investor Owned Utilities in Docket No. 160096-EI (as summarized in **Attachment A**). In summary, compared to the 2016 Risk Management Plan's maximum hedging target ranges, DEF's proposed 2017 Risk Management

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Plan maximum hedging target ranges represent a reduction of [redacted] for the 1 to 12 month time period, [redacted] for the 13 to 24 month time period, and [redacted] for the 25 to 36 month time period. These further adjustments to the hedging ranges and targets were made to the 13 to 24 month time period and the 25 to 36 month time period in response to the discussion at the June 9, 2016 Florida Public Service Commission agenda conference that considered the Joint Hedging Petition Filed by the Investor Owned Utilities in Docket No. 160096-EI (consolidated with the 2016 fuel docket by Order No. PSC-16-0301-PCO-EI).

The 2017 Risk Management Plan was developed after consideration of the on-going reviews and discussions regarding the hedge percentages, DEF's overall fuel mix, the continued uncertainty in future natural gas prices and volatility, and the need to maintain a balanced approach to the management of fuel cost risk. DEF believes having a rolling approach that gradually increases hedging percentages over time by layering in hedging transactions that ultimately target to have approximately [redacted] to the market for the rolling 1 to 12 month period represents a balanced fuel price risk management approach that results in certainty of fuel costs for a portion of projected fuel costs while providing customers [redacted] of exposure to actual market prices. In addition, DEF believes continuing to hedge a portion for the rolling future periods beyond the front 12 months by gradually increasing hedging percentages over time by executing transactions provides benefits by ensuring a consistent execution approach over a multi-year period given the number of factors that can ultimately impact prices and trends. In addition, this approach ensures a degree of price and volatility risk mitigation from one fuel period to another. Given DEF's hedging percentage targets, DEF will continue to participate in the spot natural gas market for a portion of its overall estimated natural gas usage.

Transportation Fuel Surcharge

With respect to coal river transportation estimated fuel surcharge exposures, DEF will no longer execute financial hedge transactions for periods after 2016.

Summary

Through the remainder of 2016 and during 2017, DEF will continue to monitor its fuel forecast and will continue to execute hedges over time to attempt to manage to the hedge percentage targets outlined for a portion of its projected burns for natural gas, with the exceptions discussed above. This hedging approach is consistent with DEF's existing strategy and allows DEF to continue to monitor the market and fuel forecast updates. The hedging targets for each of the respective periods are included in DEF's Regulated Utilities Risk Limits in **Attachment B.**

Item 3. Identify and quantify each risk, general and specific, that the utility may encounter with its fuel procurement.

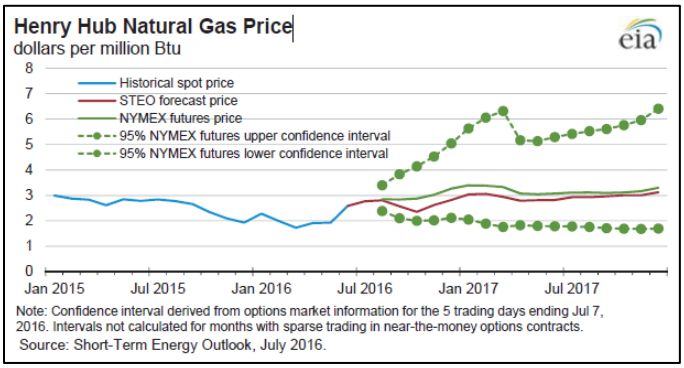
DEF has identified specific and general risks associated with the procurement of fuels and power optimization activities. The specific risks include fuel price risk, supplier performance and default risk, liquidity risk, credit risk, product availability risk, and changes in forecasted volumes. The general risks include weather related events such as hurricanes, extreme weather variations from forecast, business continuity, and changes in environmental rules and regulations. Described below is further information on the specific and general risks, and DEF's activities to manage overall exposure to these risks including the processes that DEF has in place to monitor and quantify risks.

Fuel Price Risk

Commodity prices are constantly changing and as a result by definition contain volatility. DEF's customers are exposed to the risk of fuel price movements over time which could result in significant variability in projected and actual fuel costs. As noted in Item 2 above, natural gas makes up the largest component of DEF's overall fuel costs and hedging activities. Natural gas the physical fuel is procured under standard industry contracts that are based on published market index pricing that exists during the time period the fuel is delivered. The published market index prices paid by DEF for natural gas will fluctuate with changes in market prices until the respective first of the month market index or daily-published market index price settles and the product is delivered. As a result of fuel cost risks and volatility, DEF has implemented an approved financial hedging plan to reduce the risk of future price movements for a percentage of its fuel exposure for natural gas by executing financial hedging transactions over time that lock in prices. By definition, fixed prices are no longer subject to future price movement and as a result volatility and fuel cost risks are reduced. With respect to coal, DEF executes standard industry physical supply agreements to fix and/or collar the price of the underlying coal but is exposed to fuel surcharges in the transportation agreements. Absent hedging as defined by Order No. PSC-02-1484-FOF-EI (i.e. the Hedging Order), Order No. PSC-08-0667-PAA-EI (i.e. Clarifying Hedging Order), and fixed price coal supply contracts, the projected fuel costs for coal and natural gas could vary significantly due to changing market prices over time.

With respect to quantifying the potential statistical range of natural gas prices within a 95% confidence interval of natural gas prices for 2017, DEF is providing information from the US Energy Information Administration (EIA) July 2016 Short-Term Energy and Summer Fuels Outlook. EIA is forecasting Henry Hub spot prices to average $2.95/MMBtu in 2017 with a lower and

upper limit with a 95% confidence interval of $1.79/MMBtu and $5.69/MMBtu.



Neither DEF nor any forecaster can predict where actual prices and volatility will be in the future and DEF's fuel hedging practices are not intended to "out-guess" the market. This information above regarding projected natural gas prices and ranges is being provided because fuel costs are impacted by changing and uncertain fuel prices and volatility over time.

DEF will manage and reduce fuel price risk and volatility for a portion of its forecasted natural gas by utilizing financial transactions over time as outlined above for natural gas. In addition, DEF enters into standard industry coal supply physical agreements to fix the price of the underlying commodity. As a result of these actions, DEF reduces its overall risk to changing prices in projected fuel costs for its customers over time.

With respect to monitoring and quantifying fuel price risk, the company's Risk Management function independently monitors and reports on the financial hedging activities and the percentage of projected fuel burns that have been procured as compared to the established procurement ranges and targets for each respective product and period. In addition, the Company performs multiple periodic fuel and purchased power cost forecast updates each year, which incorporate any updates needed for hedge positions, fuel and emission prices, unit maintenance schedules, load forecasts, and other operating parameters. The updated fuel and purchased power forecasts are point in time estimates and are summarized and published to ensure there is a regular review of projected fuel and purchased power costs. In addition, the Company performs standard statistical stress tests and portfolio analyses on an as needed basis.

Supplier Performance and Default Risk

Supplier performance and default risk represents the risk of additional cost and/or supply loss that DEF could incur if a supplier defaults on a physical or financial obligation and is not able to fulfill the terms of an agreement. The estimated aggregate dollar amount of supplier performance and default risk

for the portfolio is based on the volume, duration, and price of the agreements as compared to the current estimated market value of the agreements.

DEF reduces supplier performance risk by engaging in business with a number of approved suppliers, executing agreements within contract approval limits and credit parameter limits, monitoring delivery performance of suppliers, and, if possible, incorporating contractual provisions that allow for non-performance remedies in the case of default. In addition, if a supplier defaults, DEF also maintains offsite inventories for natural gas and on-site inventories for coal and fuel oil. For activities associated with hedging under financial agreements, the Credit function within Risk Management monitors all open positions and reviews the estimated exposure for each third party company to ensure that DEF maintains the appropriate collateral balances as compared to contractual thresholds established.

With respect to monitoring and quantifying the level of supplier performance and default risk in fuel agreements, the Credit function within Risk Management monitors the amount of default risk associated with financial and physical fuel agreements. The review is based on contractual volumes, duration, and prices as compared to the current estimated value of the open positions in the agreements that have yet to be delivered or financially settled.

Liquidity Risk

Liquidity risk represents the risk that DEF could not meet the collateral requirements generated from physical agreements and financial agreements. As discussed above, DEF currently manages natural gas price risk and volatility for a portion of its forecasted fuel costs through the use of financial hedging agreements. To manage default risk, these agreements contain provisions that require the posting of collateral if contractual thresholds are surpassed. The collateral requirements of the portfolio are based on the volume, duration, price, and collateral threshold levels of the agreements as compared to the current estimated market value of the agreements.

DEF manages and reduces liquidity risk by conducting business with a number of counterparties to maximize the collateral threshold levels in individual agreements. For activities associated with hedging under financial agreements, the Credit function within Risk Management monitors all open positions and reviews the estimated market exposure for each third party company on a daily basis to ensure that DEF only posts the appropriate collateral balances as compared to contractual thresholds.

With respect to monitoring and quantifying the level of liquidity risk, Risk Management independently calculates, monitors, and reports on the amount of liquidity risk associated with financial and physical agreements. The review is based on contractual volumes, duration, and prices as compared to the

current estimated value of the open positions in the agreements that have yet to be delivered or financially settled. Risk Management performs standard statistical stress tests and portfolio analysis on an as needed basis.

DEF continues to monitor the Dodd-Frank Wall Street Reform and Consumer Protection Act and the Commodity Futures Trading Commission's rules that implement the Dodd-Frank Act (collectively, the "Dodd-Frank Act").

The Dodd-Frank Act provides for the comprehensive regulation of swaps and security-based swaps, applying in respects to all "swaps" (as defined by the Dodd-Frank Act), including the bilateral and over-the-counter (OTC) derivatives markets, as well as swaps and options embedded in physical forward transactions. Generally, the Dodd-Frank Act provides for certain exception from the mandatory clearing requirements and other transactional efficiencies for participants that are "end-users" transacting in commodity hedging activities to mitigate or hedge physical risk. DEF enters into commodity hedges to mitigate commercial risk and/or hedge physical positions, rather than as part of a speculative swap business. Therefore, DEF's commodity transactions are eligible for the end-user exception and the associated exception from the mandatory clearing requirements.

The Dodd-Frank Act also has rules and requirements for record keeping and reporting. Every party to a swap must keep records over certain periods of the transaction. DEF is maintaining records in accordance with the requirements of the CFTC regulations. As an end-user, DEF can shift, and does shift, the reporting obligation to swap counter parties. The CFTC has not finalized the rules for margining and clearing requirements, as well as the position limit requirements. DEF is continuing to monitor and review any issued rules and the timing of their implementation to prepare for applicable compliance requirements. DEF continues to monitor the potential impact of the rules on its financial hedging transactions. However, it is difficult to predict how the market will ultimately adjust to the new regulations.

In general, the implemented and proposed regulations have changed the requirements and may affect the derivatives markets. For example, margining requirements could require counterparties to post additional margin and maintenance margin for OTC derivatives, which would then increase the liquidity requirements needed to support these activities. Although end-users would not be subject to mandatory margining requirements, the marketplace would expect margin for security and requirements applicable to other participants may impact the marketplace generally. Currently, DEF has credit collateral thresholds in place with its counterparties that do not require the posting of collateral unless the market value of the hedges drops below the negotiated threshold dollar value. Additionally, DEF has negotiated bi-lateral non-margin hedging agreements with counterparties where DEF and the

counterparty can agree to not have margin requirements for financial hedging transactions. If some of DEF's counterparties are subject to higher liquidity requirements due to the current or future proposed regulations, DEF could be subject to 1) potential increases in bid / offer spreads on market hedge transactions, 2) reduction by certain counterparties in the use of non-marginable OTC transactions, and/or 3) potential reduction in the number of counterparties who will be available for hedging transactions with DEF. It is also unclear how the position limit rules, which have not been finalized, will impact DEF's activities and compliance obligations.

As noted above, DEF continues to comply with the requirements of the Dodd-Frank Act, as well as monitor any rule making.

Credit Risk

On a daily basis, the Credit function within the Risk Management function calculates, monitors, and reports on the credit risk associated with the Company's fuel procurement and hedging activities. The Credit function utilizes industry-specific credit evaluation practices and has specific criteria that are used to measure credit risk and ensure counterparties' credit is monitored and reviewed. The Credit function monitors all positions and reviews the mark-to-market exposure for each third party company to ensure that based on the current market value of open hedge positions and the credit quality of the third party companies the appropriate level of collateral is posted or received as compared to the contractually established threshold. To date, DEF has not experienced any credit losses with respect to its hedging program activities.

With respect to financial transactions, prior to executing any financial transaction with a third party company, DEF and the third party company must have an International Swap Dealer Agreement (ISDA) in place. The ISDA is a standard industry contract that is used by industry participants to enter into Over the Counter bi-lateral transactions (OTC transactions). All ISDA agreements are negotiated by the Legal group and reviewed as needed with Credit, FSO, and Accounting to ensure the appropriate terms and conditions are included. As part of the process of setting up a new financial agreement, a credit evaluation is performed on the third party company by the Credit function. There are universal principles of credit strength that are evaluated before credit is granted. Among these principles are company size, industry characteristics and trends, profitability, liquidity, cash flow, interest coverage, and capital structure. DEF evaluates counterparties using a consistent analytical approach and the credit ratings are based on both external ratings and an internal evaluation. The credit rating process includes obtaining counterparty background information, identifying any existing Standard & Poor's (S&P) and/or Moody's ratings for the counterparty, and performing a financial statement analysis. The financial statement analysis

includes, but is not limited to, a review of revenue trends, metric calculations and trends evaluation for Free Funds from Operations, Total Debt to Tangible Net Worth, Funded Debt to Capital, Interest Coverage, Operating Cash Flow and Liquidity. If the counterparty is a bank, Tier I and Total Capital Ratios are also reviewed. Once the credit evaluation is complete, a credit rating is assigned to the third party company and, if appropriate, a credit line is extended. The third party company's assigned credit rating and credit limit dictate the size and duration of financial hedging transactions that DEF can enter into with it.

As described, on a daily basis the Credit function independently monitors, calculates and reports on collateral exposure. In addition, with respect to monitoring agreements that require the posting of margin based on established contractual thresholds, the company may ask for margin or send out margin to the third party company to ensure exposures are within established contractual thresholds.

Product Availability and Changes in Forecasted Volumes

DEF must have access to needed physical fuel supplies, adequate product delivery capabilities and inventory to meet projected fuel requirements. Without access to needed fuel supply and inventory, DEF is exposed to the risk of not being able to economically and reliably dispatch the generation fleet for its customers.

DEF manages and reduces this risk by entering into physical supply contracts, as well as needed pipeline, railroad, barge and trucking agreements for the purchase and delivery of coal, natural gas, and fuel oil that provide the ability to meet projected burns. In addition, DEF maintains on-site inventory for coal and fuel oil to provide fuel supplies to support on-going operations and ensure supplies are available if unexpected delivery delays, storm curtailments, or other events that could affect fuel supply availability occur. DEF also holds off-site onshore high deliverability natural gas storage capacity that provides additional access for a portion of its current generation natural gas needs when natural gas supplies are curtailed. In addition, DEF currently has firm transportation on Gulfstream Natural Gas, Florida Gas Transmission (FGT), and Southern Natural Gas (Sonat) and has access to onshore gas supplies via contractual volumes delivered on Southeast Supply Header, Destin Pipeline Company, the Transco Mobile Bay South Lateral and an agreement for supply from Elba Island LNG into FGT via the Sonat Cypress Pipeline to meet it current generation needs. DEF actively monitors forecasted fuel burns, actual fuel burns, and fuel inventory levels. Based on its on-going monitoring efforts DEF may make procurement adjustments to manage any changes to the forecasted volume and delivery timing of contracted supplies because of actual burns, changes to forecasted fuel burns, and inventory levels that can be caused by factors such as

weather deviations, fuel prices, plant outages, and purchased power opportunities.

With respect to monitoring and quantifying the level of risk associated with ensuring adequate fuel supply, Risk Management independently monitors and reports on the amount of fuel procured versus projected burns. In addition, the front office performs analyses that quantify the amount of fuel and transportation needed to support projected burns and inventory needs. Lastly, the Company performs periodic forecast for fuel burns and purchased power and produces summary reports for review and monitoring of projected fuel burns.

General Risk

DEF is subject to weather events and hurricanes. As detailed above, DEF reduces the overall risks associated with weather events and other potential fuel delivery curtailments and delays by maintaining on-site inventories, off-site inventories and continuing to diversify its natural gas supply to more secure onshore locations as the Company's overall gas generation has grown. DEF is also subject to events that could require FSO employees to perform required work functions at locations other than their normal work location. With respect to this risk, the FSO Department has business continuity plans in place that are reviewed and tested periodically to ensure that offsite locations are functional. Lastly, DEF is subject to changes in environmental rules and regulations.

Item 4. Describe the company's oversight of its fuel procurement activities.

The Finance and Risk Management Committee (FRMC) of the Board of Directors as well as the Company's Senior Management, defined as the Chief Executive Officer (CEO) and his/her direct reports, provides guidance and oversight to Duke Energy's financial risks. The Chief Risk Officer (CRO) updates the FRMC of any material risks and risk management activities of the enterprise at periodic committee meetings. The Transaction and Risk Committee (TRC) is responsible for oversight of the Corporation's Risk Management activities. The TRC is comprised of senior executives from varying functional areas. The CRO is responsible for annually reviewing the corporate Commodity Risk Policy and Corporate Credit Policy, and the TRC is responsible for approving substantive changes to the policies. The CRO reviews corporate risks, resulting mitigation decisions including fuel hedging, and procurement activities. The TRC reviews transactions that exceed individual senior management committee approval authorities. Senior management committee approval authorities are outlined in the Company's Approval of Business Transaction policy (ABT). In addition, the Company

maintains a risk management control manual, together with specific risk and credit limits that apply to the activities of DEF. These policies, processes, and limits are reviewed at least annually by the Front Office and Risk Management, and are approved by CRO or the Chief Financial Officer (CFO) as required.

DEF has included the Regulated Utilities Risk Management Control Manual, the Duke Energy Commodity Risk Policy, the Duke Energy Credit Policy, the DEF Regulated Utilities Risk Limits and the DEF Regulated Utilities Credit Limits as **Attachments H, D, E, B, and F**, respectively.

With respect to day-to-day independent oversight and controls in place to oversee FSO's activities, the company uses the "three-office" structure which includes FSO and Energy Supply Analytics (Front Office), Risk Management (Middle Office), and Regulated Accounting (Back Office) to provide the necessary independent oversight and monitoring of its fuel procurement, power optimization, and hedging activities.

The "three-office" structure is an accepted industry practice with the Front Office, Middle Office, and Back Office each functioning as independent departments, which ensures the required segregation of duties and the existence of independent oversight and controls over key activities. In addition, the Legal organization provides critical contractual support to ensure that the Front Office contracts are reviewed with FSO and contain legal provisions that reduce risks that could affect the Company. The IT Enterprise Application Solution Support organization provides on-going support related to trading system operations and functioning. Treasury and Disbursement Services provide appropriate support when disbursing funds to counterparties via checks, wires, or automated clearinghouse payments. These support organizations are independent from the Front Office.

<u>Front Office</u>
DEF has a structured procurement process where Requests for Proposals are issued periodically to procure needed competitive fuel supply. As noted above, the fuel procurement contracting and settlement activity is supported by the Legal and Regulated Accounting function. Front Office management is responsible for ensuring employees are authorized before they are allowed to trade commodities on the Company's behalf. In addition, there is a corporate Energy Supply Bulk Power Marketing & Trading Delegation of Authorities as well as a corporate Approval of Business Transactions Delegation of Authorities, which provides the required approvals for fuel related procurement activity based on estimated costs and duration of fuel related contracts. Front Office management is also responsible for ensuring that employees who trade commodities on the Company's behalf attend required periodic training conducted by Risk Management and Regulatory

Compliance. DEF has included the Duke Energy Commodity Risk Policy, Duke Energy Credit Policy, DEF Regulated Utilities Risk Limits and DEF Regulated Utilities Credit Limits in **Attachments D, E, B, and F**, respectively. In addition, DEF has included the Duke Energy Supply Bulk Power Marketing & Trading Delegation of Authorities, the Duke Energy Commodities Approval Matrix from the ABT and the Risk Management Employee Acknowledgement as **Attachments G, C, and I,** respectively.

Middle Office

Risk Management monitors Front Office activity by quantifying, monitoring, and reporting risks associated with fuel procurement, power optimization, and hedging activities. Risk Management is accountable to the enterprise for independent oversight, measurement and reporting of Front Office activities to management. Risk Management monitors and reports on Front Office activities and will report immediately any non-compliance as required within the reporting and control limit structures as defined by the Risk Management Guidelines. Lastly, Risk Management publishes credit limit and exposure reports to ensure that counterparty credit limits are monitored and adhered to and administers margin activity as required under agreements with counterparties to reduce credit and default risk.

Regulated Accounting

Accounting is also independent from Front Office and performs control functions on a daily, weekly or monthly basis which include, among other things, deal validation, transaction confirmations, close accounting, general ledger balance sheet account reconciliations, settlements/cash transfers, processing payments/receipts, accounting for hedging activities and derivatives, and performing certain compliance activities as defined and/or required by various regulatory agencies (e.g. Securities and Exchange Commission, Financial Accounting Standards Board, Federal Energy Regulatory Commission, Public Service Commission). Related to accounting for hedging activities and derivatives, Duke Energy's Derivatives policy is followed. This policy is reviewed and updated as necessary and at least annually.

Item 5. Verify that the utility provides its fuel procurement activities with independent and unavoidable oversight.

As described in Item 4, the Company has a robust independent oversight culture and organizational design with processes in place to ensure the identification, monitoring, and reporting of risks accompanying independent controls for monitoring and reporting on fuel procurement, power optimization, and hedging activities. The key components of the oversight functions and processes are further described below.

The Finance and Risk Management Committee of the Board of Directors (FRMC)

The FRMC is primarily responsible for the oversight of risk at Duke Energy. This oversight function includes, but is not limited to, review of Duke Energy's risk exposure as related to the overall enterprise portfolio and review of the financial exposures undertaken by the company in light of the approved Global Risk Management Policies. Such exposures include physical and financial positions in the commodities markets. The Committee is comprised of a minimum of two members of the Board.

Transaction and Risk Committee (TRC)

The TRC is responsible for oversight of the corporation's risk management activities as well as reviewing proposed business transactions and risk management activities that require approval by the President and CEO, the Board of Directors, or a committee of the Board of Directors in accordance with the ABT Policy. The membership of the Committee shall consist of Senior Management Committee members of the Corporation, as designated by the President and CEO, plus the following individuals:

- Chief Risk Officer
- Treasurer

Additional members of executive leadership may be appointed to the Committee by the President and CEO. These appointments should be reviewed by the President and CEO on an annual basis.

Regulated Utilities Risk Management (Risk Management)

Duke Energy has an independent Risk Management section for its regulated utilities operations, which is overseen by the TRC Secretary and Director, Regulated Utilities Risk Management who reports to the CRO. The Risk Management group is comprised of a credit risk management function and a market risk management function. Risk Management's credit function provides independent credit evaluation of trading and procurement counterparties, performs credit reviews of Duke Energy's suppliers and customers, assists in drafting and reviewing credit language in various agreements, and monitors and reports on credit exposures daily. Risk Management's market risk function independently reports on fuel procurement and hedging activities and performs independent analysis as required. Risk Management independently develops the methodologies for measuring and evaluating risk.

Regulated Utility Risk Management Control Manual and Regulated Utilities Risk Limits

As part of the overall risk management structure and oversight process at the

Company, the Company has a Regulated Utility Risk Management Control Manual, Regulated Utilities Risk Limits and Regulated Utility Credit Limits. These are reviewed by Front Office and Risk Management, and approved by the CRO or the CFO as required.

The Regulated Utilities Risk Management Control Manual provides the descriptions of the objectives and operations of the regulated businesses, the overall control environment in which they operate, and the structure and responsibilities of the various groups involved in the control function. DEF's Regulated Utilities Risk Limits contain the limits and approved activities for DEF. In aggregate, these documents provide for the oversight and controls, roles and responsibilities, and the approved activities associated with fuel procurement contracts, fuel hedging activities and power activities. Duke Energy's Credit Policy provides the overall objectives and general operating practices for evaluating, measuring, mitigating, and reporting credit risk associated with FSO activities. In addition, the Company has established Credit Risk Limits define prescribed credit limits, including contract duration criteria for counterparties based on credit metrics.

Internal Audit
Internal Audit provides independent assurance and consulting services that ensure compliance, effective corporate governance, adherence to established procedures, and operational effectiveness for all major areas of the Company. With respect to FSO activities, Internal Audit performs periodic audits that focus on items such as compliance with established procedures, off-premise activity, payment terms under fuel contracts, and other trading and procurement activities.

Legal and Regulated Accounting
Legal performs contract reviews with the Front Office during drafting and prior to final execution. In addition, Regulated Accounting which includes the Back Office performs, among other things, on a daily, weekly, or monthly basis, deal validation, transaction confirmations, close accounting, general ledger balance sheet account reconciliations, settlements/cash transfers, processing payments/receipts, accounting for hedging activities and derivatives, and compliance activities as defined and required.

Item 6. Describe the utility's corporate risk policy regarding fuel procurement activities.

The Company has a Regulated Utility Risk Management Control Manual, a Commodity Risk Policy, a Credit Policy, and Regulated Utility Risk and Electric Credit Limits. In addition, the Company has the Duke Energy Supply Bulk Power Marketing & Trading Delegation of Authority, and the Duke

Energy Commodities Approval Matrix from the Approval of Business Transactions policy that outline the approval requirements for procurement activities for respective individuals and management levels based on the tenor and estimated dollar amounts of agreement, subject to the requirements of the Approval of Business Transactions policy.

These documents and processes in aggregate outline the expectations, policies, responsibilities, and limits associated with the corporate risk oversight and approved activities for the Company's fuel procurement practices. In addition, as described in detail in item 4, the Company has developed oversight functions and processes that are followed with respect to fuel procurement, power optimization, and hedging activities. DEF has included the Regulated Utilities Risk Management Control Manual, Duke Energy Commodity Risk Policy, Duke Energy Credit Policy, the DEF Regulated Utilities Risk Limits, the DEF Regulated Utilities Credit Limits, the Duke Energy Supply Bulk Power Marketing & Trading Delegation of Authorities, the Duke Energy Commodities Approval Matrix from the ABT, and the Risk Management Employee Acknowledgement as **Attachments H, D, E, B, F, G, C, and I**, respectively. The fuel purchase and related activities are identified under the Duke Energy Supply Bulk Power Marketing & Trading Delegation of Authority, DEF Regulated Utilities Risk Limits and the Duke Energy Commodities Approval Matrix from the ABT.

Item 7. **Verify that the utility's corporate risk policy clearly delineates individual and group transaction limits and authorizations for all fuel procurement and hedging activities.**

DEF has approval requirements, policies, and authorizations in place that outline authorizations for fuel procurement and financial hedging activities. DEF has included DEF's Regulated Utilities Risk Limits and corporate Duke Energy Commodity Risk Policy in **Attachments B and D**, respectively. These policies and guidelines outline roles and responsibilities of each group, deal execution processes, and allowed products, as well as control limits such as volumetric, tenor, and liquidity limits and deal validation and valuation processes. Additionally, the Duke Energy Supply Bulk Power Marketing & Trading Delegation of Authority and the Duke Energy Commodities Approval Matrix from the ABT outline the approval requirements for procurement activities for respective individuals and management levels based on the tenor and estimated dollar amounts of agreement, subject to the requirements of the Approval of Business Transactions policy. The Duke Energy Supply Bulk Power Marketing & Trading Delegation of Authorities, and the Duke Energy Commodities Approval Matrix from the ABT are included in **Attachments G and C**, respectively.

Item 8. Describe the utility's strategy to fulfill its risk management objectives.

As outlined in Item 1, DEF's Plan objectives are to effectively manage its overall fuel and purchased power costs for its customers by engaging in competitive fuel procurement practices and activities, performing active asset optimization and portfolio management activities, and continuing to execute the Company's hedging program to reduce fuel price volatility risk and provide greater cost certainty for DEF's customers. Outlined below is the strategy to fulfill the risk management objectives.

First, the strategy is executed by experienced professionals who conduct and execute their activities to achieve the objectives of the plan.

One of the components of DEF's Plan objectives is to engage in competitive fuel procurement practices. Examples of the strategy executed to fulfill this objective include the issuance of periodic RFP's to solicit competitive term supply bids for coal, natural gas, and fuel oil. In addition, DEF actively manages its day-to-day fuel needs and participates in the short-term market place to access competitive supply and work closely with suppliers as needed. With respect to the strategy executed to achieve the objective of performing active asset optimization and portfolio management activities, the Portfolio Management Unit within FSO performs daily forecast to determine optimal unit commitment and dispatch based on generation costs and market prices, and together with the Power Trading Unit within FSO, monitors the hourly cost to dispatch the generation fleet compared to available market opportunities. The Power Trading Unit actively seeks opportunities to execute economic purchases and sales that reduce costs for the customers. Lastly, with respect to the strategy executed to fulfill the objectives of the financial hedging program, DEF by virtue of locking in fixed price for a portion of forecasted usage over time via its financial hedging program, achieves this objective as a portion of DEF's fuel costs are no longer subject to changing price risk and volatility due to changing fuel markets.

Along with the examples noted above, DEF's Plan activities are governed by independent controls and audits, strong processes, appropriate organizational design and oversight, deal approval requirements, and the existence of needed guidelines and procedures. The Company has established controls, guidelines, procedures, and organizations to support and independently monitor fuel procurement, hedging, and power optimization activities. As noted in items 4 and 5, the Company has a robust oversight culture and processes that include oversight by the TRC, periodic audits by Internal Audit, and independent reporting and credit monitoring by Risk Management to ensure adherence to established guidelines and procedures.

Item 9. Verify that the utility has sufficient policies and procedures to implement its strategy.

DEF maintains sufficient guidelines and procedures to implement its strategy. Please see **Attachment J** for a summary listing of the applicable guidelines and procedures.

Item 13. Describe the utilities reporting system for fuel procurement activities.

The Company utilizes multiple systems and applications to track, record, account, and report on executed fuel procurement activities. Descriptions of the primary systems, software, and other tools are provided below.

Forecasted fuel burns are prepared by the Company using a production cost simulation model called GenTrader. Fuel and other commodity price forecasts, load forecasts, purchased power deal information, generating unit operating characteristics, maintenance schedules, and other pertinent data are input into GenTrader which then simulates the system and computes a projected fuel burn requirement.

CXL is a software application used by the Company to capture natural gas physical procurement transactions as well as financial natural gas transactions. In addition to deal capture, CXL is used for deal valuation, position management, mark-to-market calculations, and settlements. CXL is integrated with the GasOps which is a natural gas scheduling tool used to match supply and deliveries. Once volumes are updated in GasOps with actual volumes, there is a process that systematically updates the physical deals in CXL.

GasOps is a software application used by the Company to match supply, transport, and deliveries for natural gas purchases, sales, and transport activity and the administration of associated contracts. The system is integrated with CXL as outlined above, which provides for greater efficiency and controls for gas related activities.

Comtrac is a software application used by the Company to capture and track physical procurement activity for coal and fuel oil. The system assists with administering contract terms and conditions, maintaining inventory levels, capturing fuel consumption information, and issuing monthly closeout processes, including invoicing, and settlements.

Risk Management utilizes a separate Credit and Market Risk System that is directly integrated with CXL to monitor and report on fuel procurement transactional activity and counterparty credit exposure.

Front Office, Risk Management, and Accounting utilize other programs such as Business Objects and Excel to summarize, evaluate, and report on fuel procurement transactions and counterparty credit evaluations. In addition, Energy Supply Analytics and Risk Management utilize Matlab, a computer programming language, to model potential forward exposures and run other fuel scenarios as needed by the business units.

Lastly, the Company has agreements with vendors to provide real time pricing feeds to monitor real-time natural gas, fuel oil, and power market prices.

Item 14. Verify the utility's reporting system and other tools consistently and comprehensively identifies, measures and monitors all forms of risk associated with fuel procurement activities.

As outlined in the response to item 13, the Company utilizes several applications to ensure procurement and financial hedging activities are captured, measured, monitored, confirmed, accounted for, and reported. The Company uses standard industry reporting templates, valuation techniques and applications. The current applications utilized by the Company provide the necessary functionality for capturing deals, summarizing fuel positions, calculating mark-to-market valuations, calculating credit and collateral exposures, generating confirmations, supporting billing and payment requirements, and maintaining needed historical information such as prices and trade data.

Item 15. If the utility has current limitations in implementing certain hedging techniques that would provide a net benefit to ratepayers, provide the details of a plan detailing the resources, policies, and procedures for acquiring the ability to use effectively the hedging techniques.

DEF does not believe that there are any current limitations to execute its hedging strategy in a reasonable and prudent manner.

Attachment A - REDACTED

Docket No. 160096
Duke Energy Florida, LLC
Exhibit No. 1 to Joint Petition

REDACTED

2016 Risk Management Plan Percentage Hedge Parameters

Period	Minimum limit	Maximum limit	Minimum Target
[redacted]			

Proposed Updates to be filed as part of the 2017 DEF Risk Management Plan to Percentage Hedge Parameters

Calendar 2017 - 2019	Minimum limit	Maximum limit	Target Percentage	Current Percent[1] Hedge	Maximum Hedging Percentage Change From 2016 Risk Management Plan
[redacted]					-25%
					-33%
					-50%

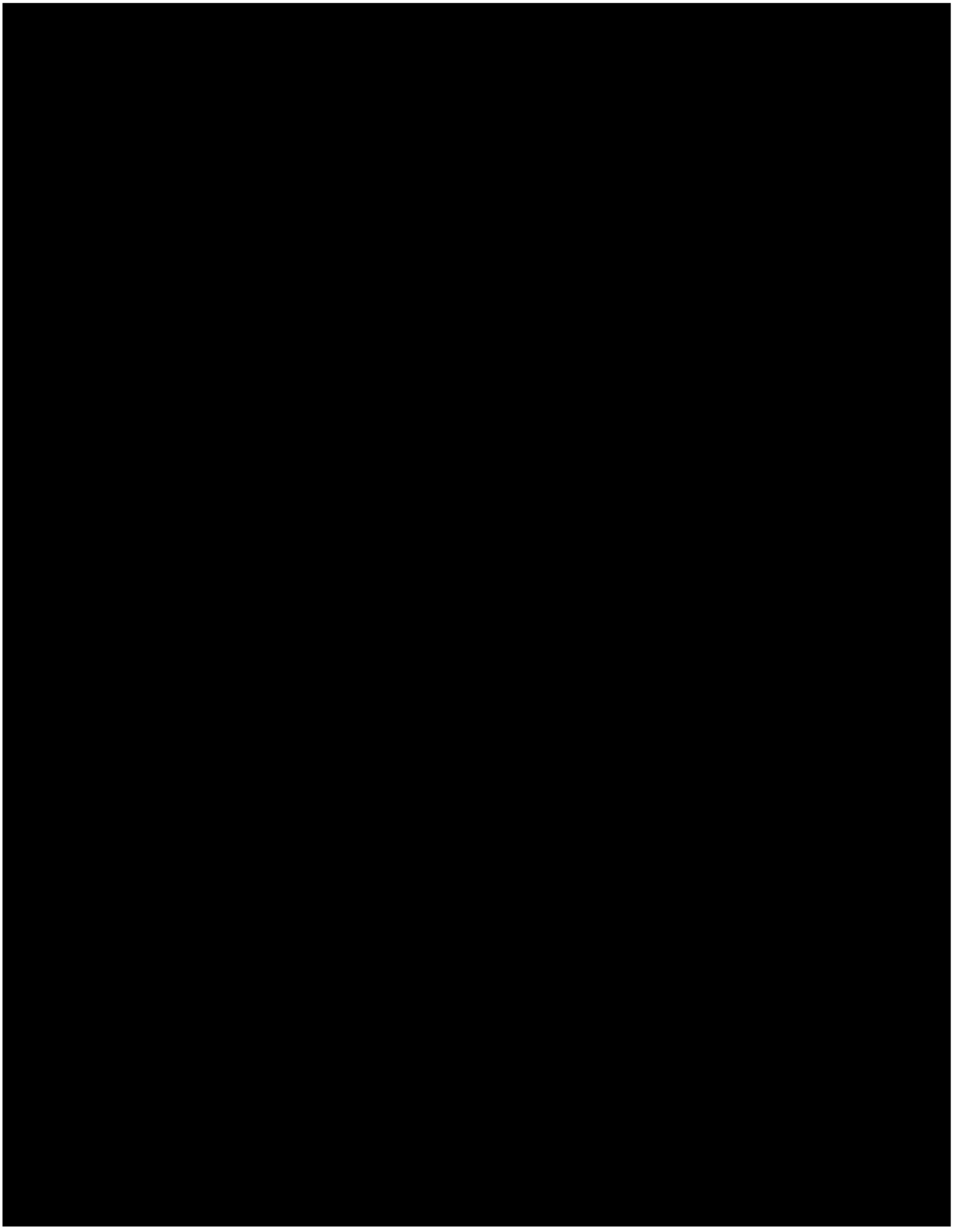
The proposed hedging targets for the respective 2017 through 2019 calendar years are based on a rolling 36 month time frame assuming the prompt month is January 2017. DEF will continue to monitor hedge percentages on a calendar year and rolling 36 month time frame as hedges are executed over time.

[1] "Current Percent Hedge" represents the hedges that are currently in place under previously approved risk management plans as of April 19, 2016.

Regulated Utilities Risk Limits

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Regulated Utilities Risk Limits



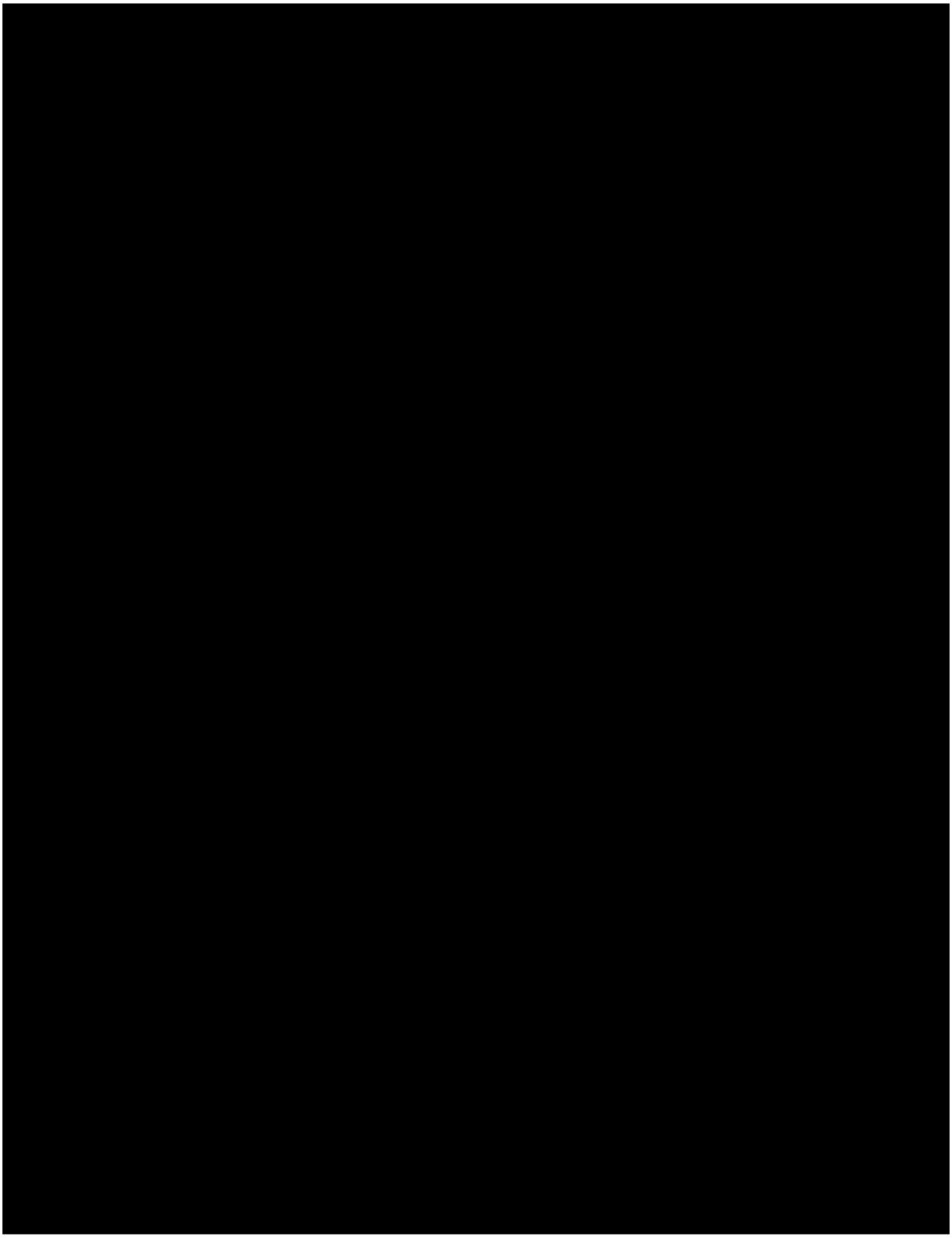
Regulated Utilities Risk Limits

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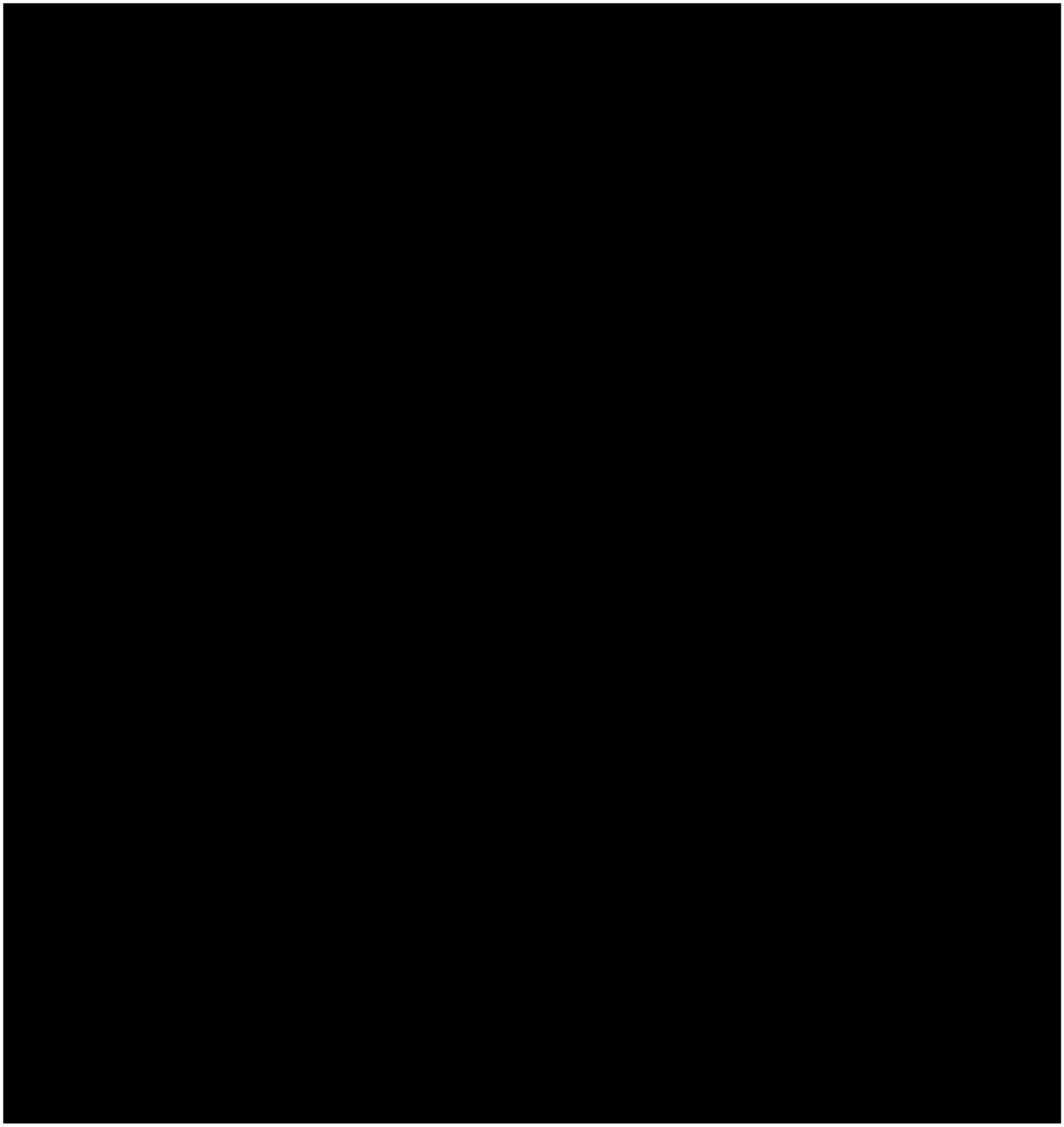
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Regulated Utilities Risk Limits



Regulated Utilities Risk Limits



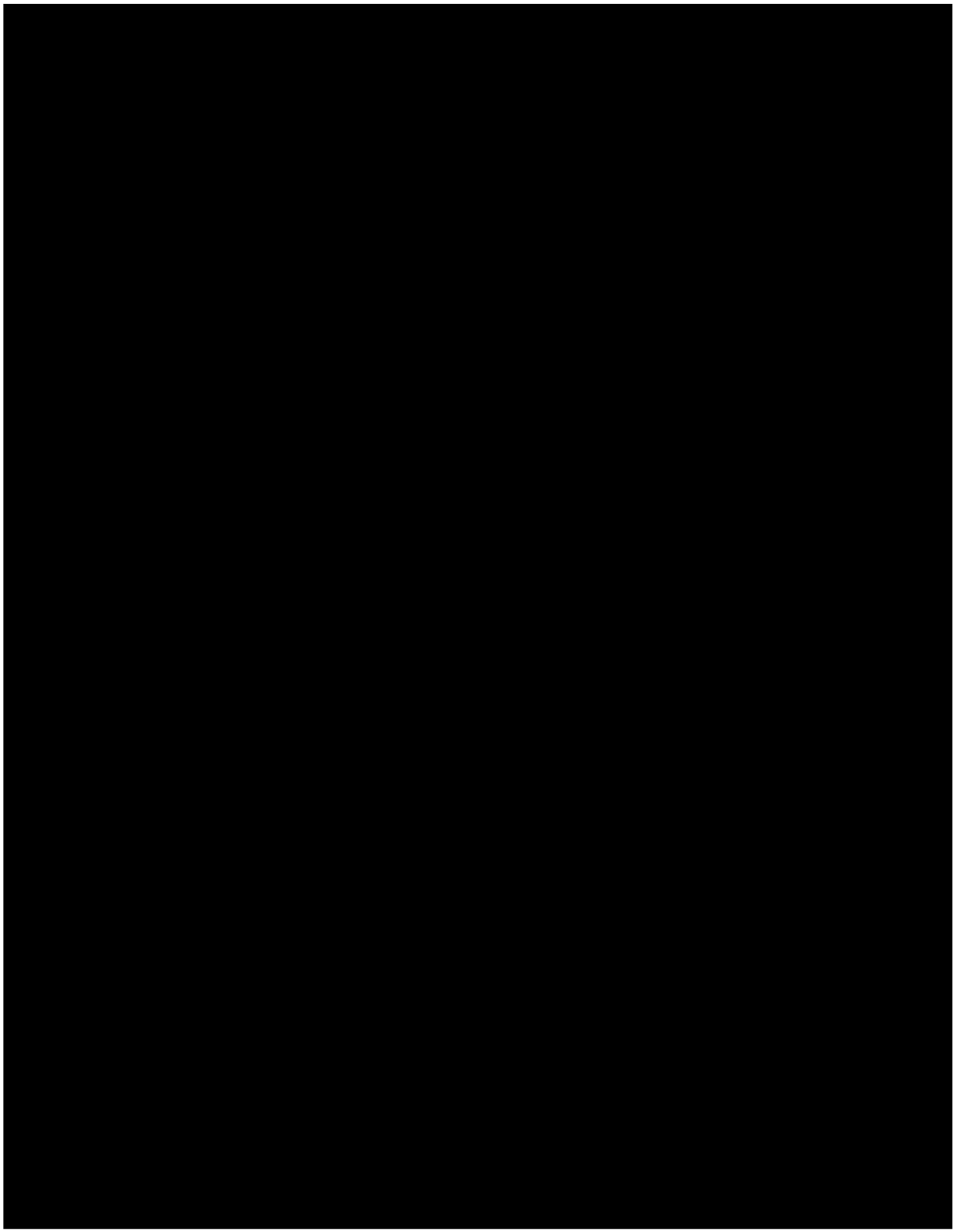
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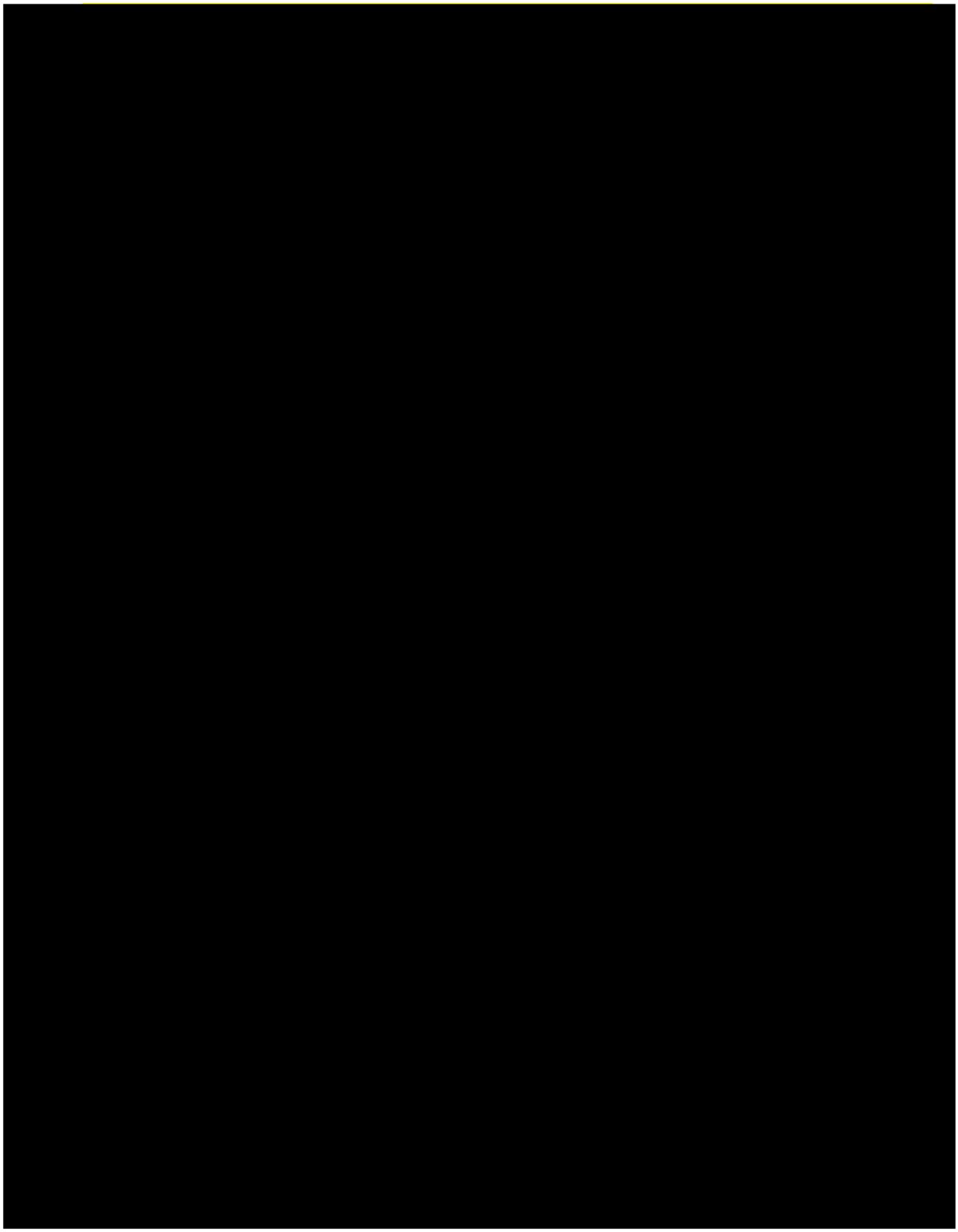
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Regulated Utilities Risk Limits



Regulated Utilities Risk Limits



Regulated Utilities Risk Limits

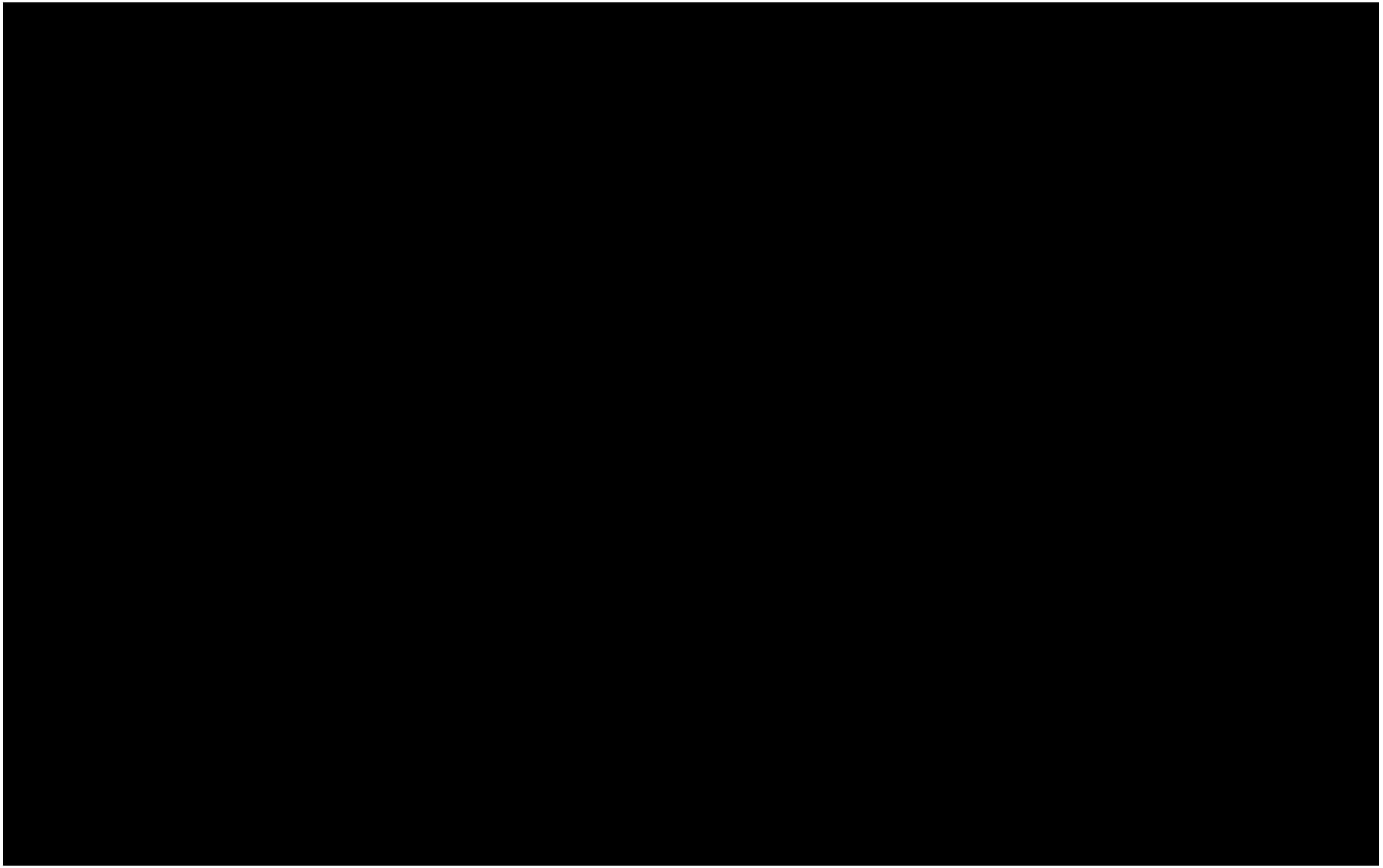


Attachment C - REDACTED

Authority Limit Matrix

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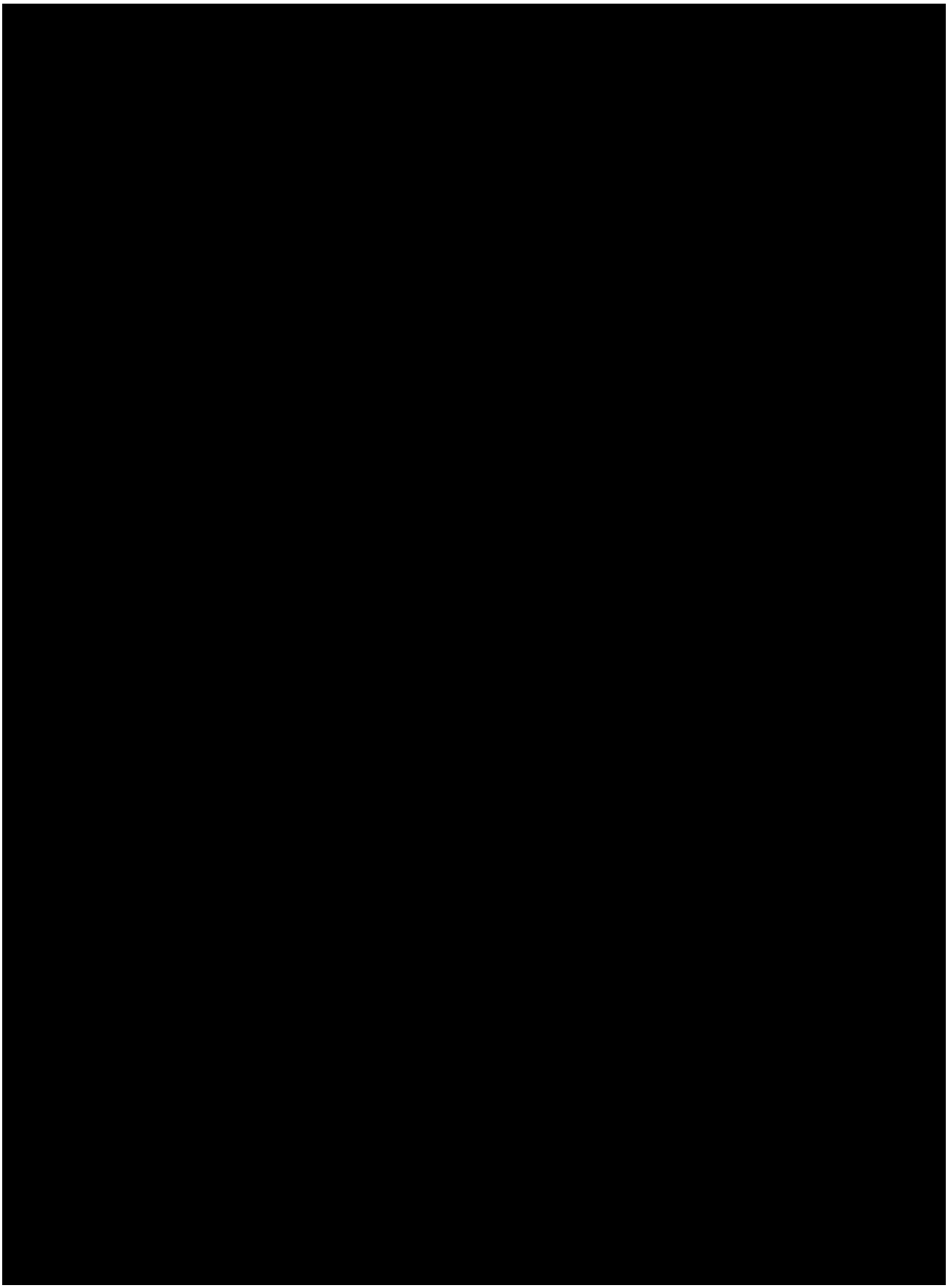
Footnotes

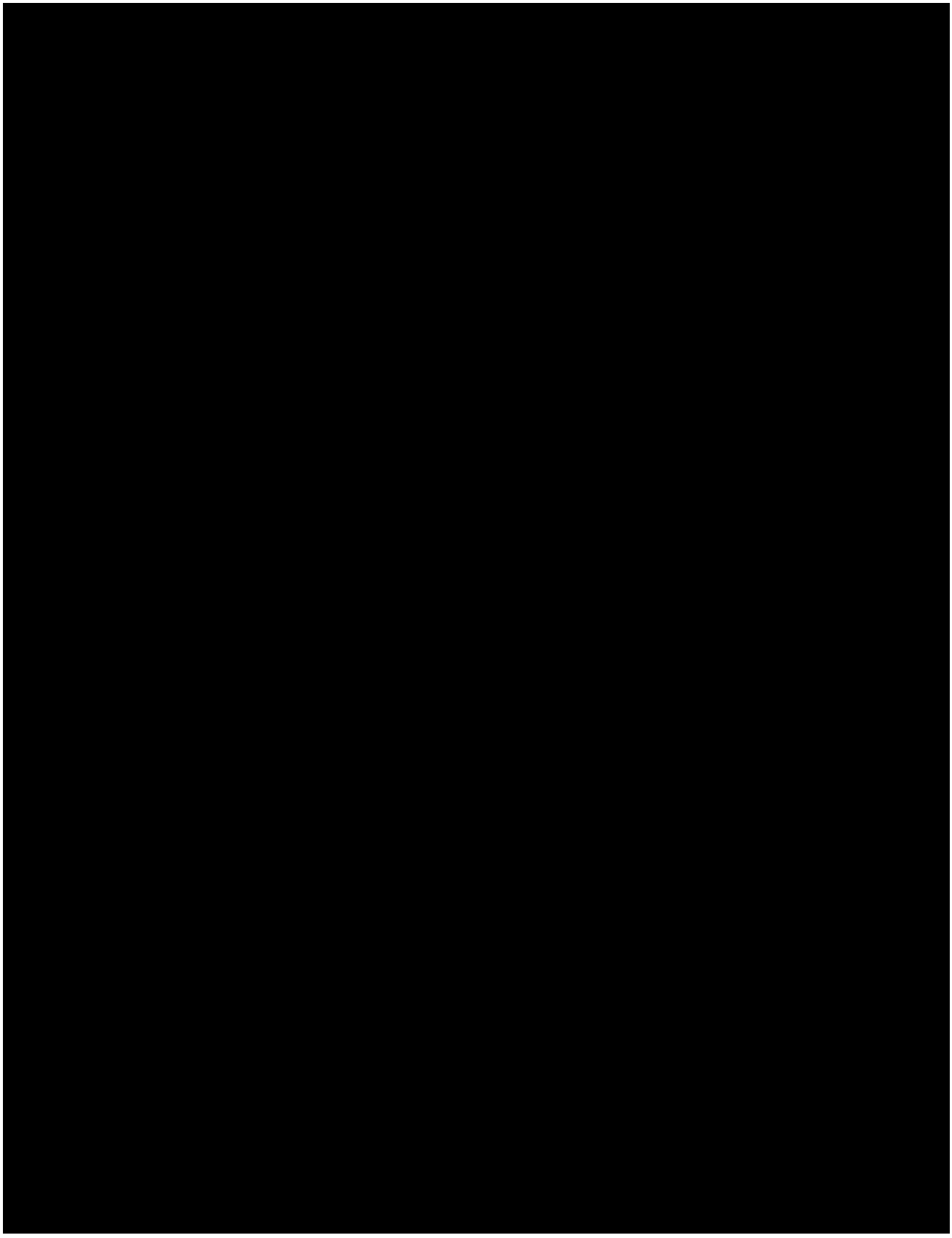


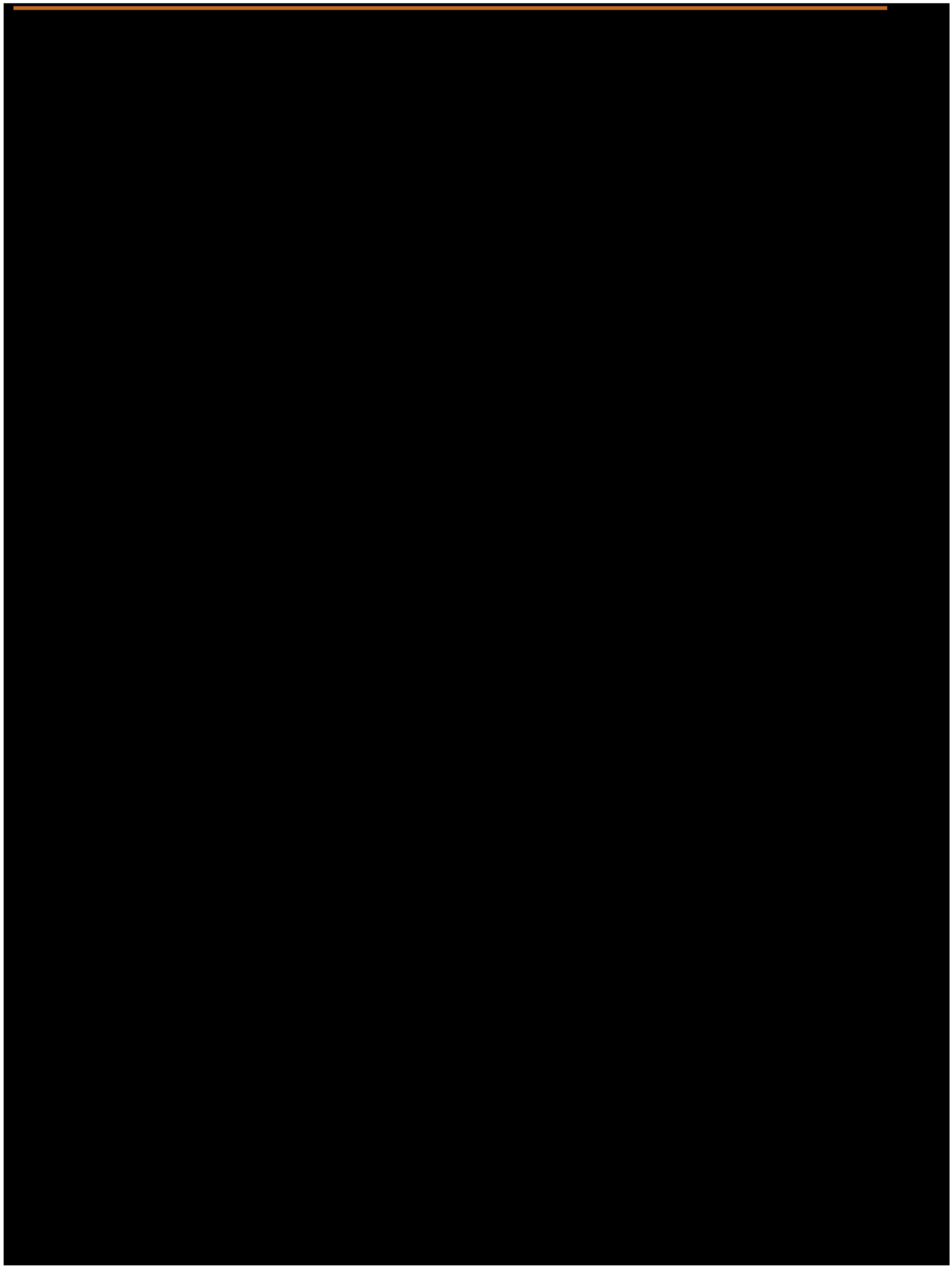
Duke Energy Policy Statement

Commodity Risk Policy

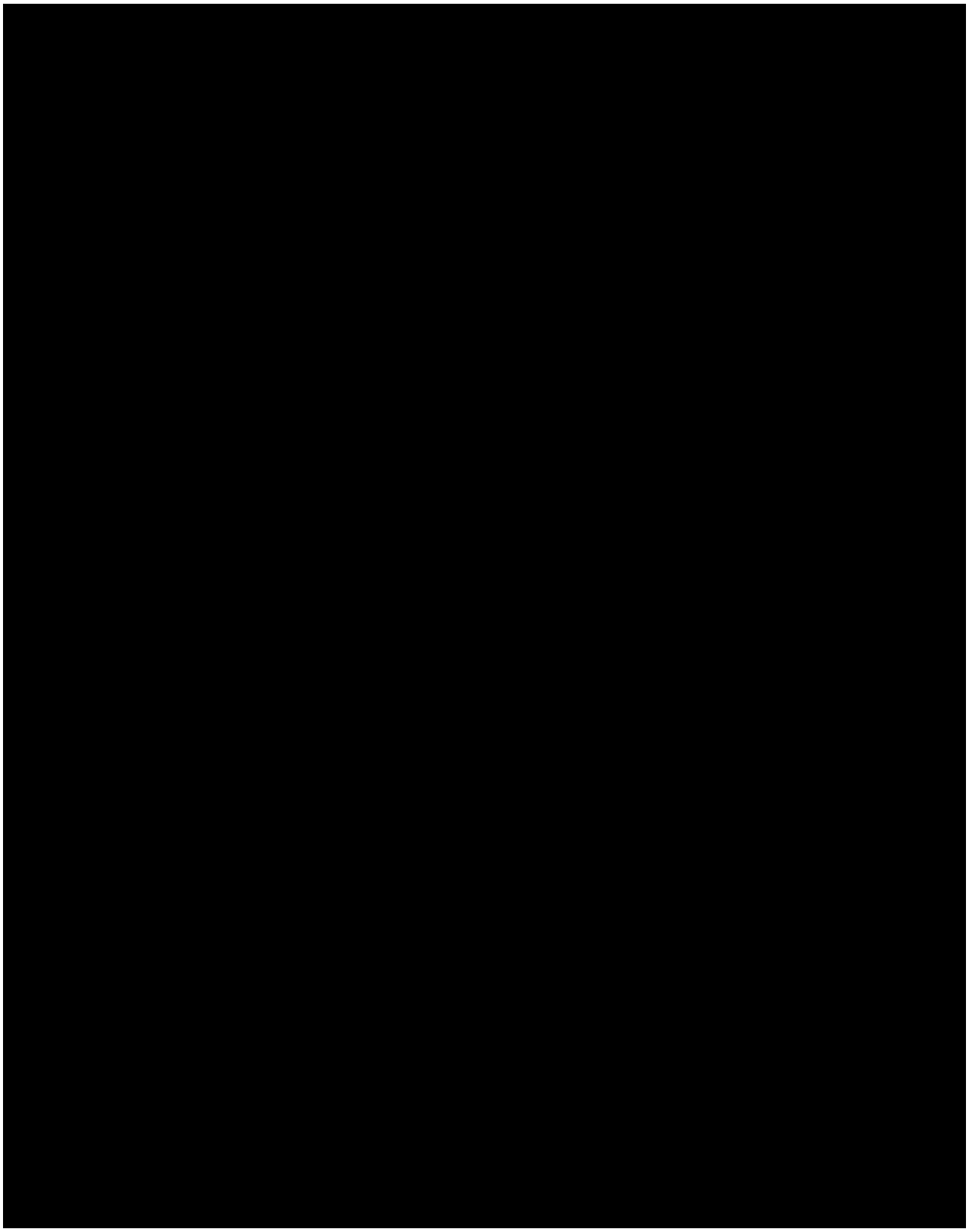
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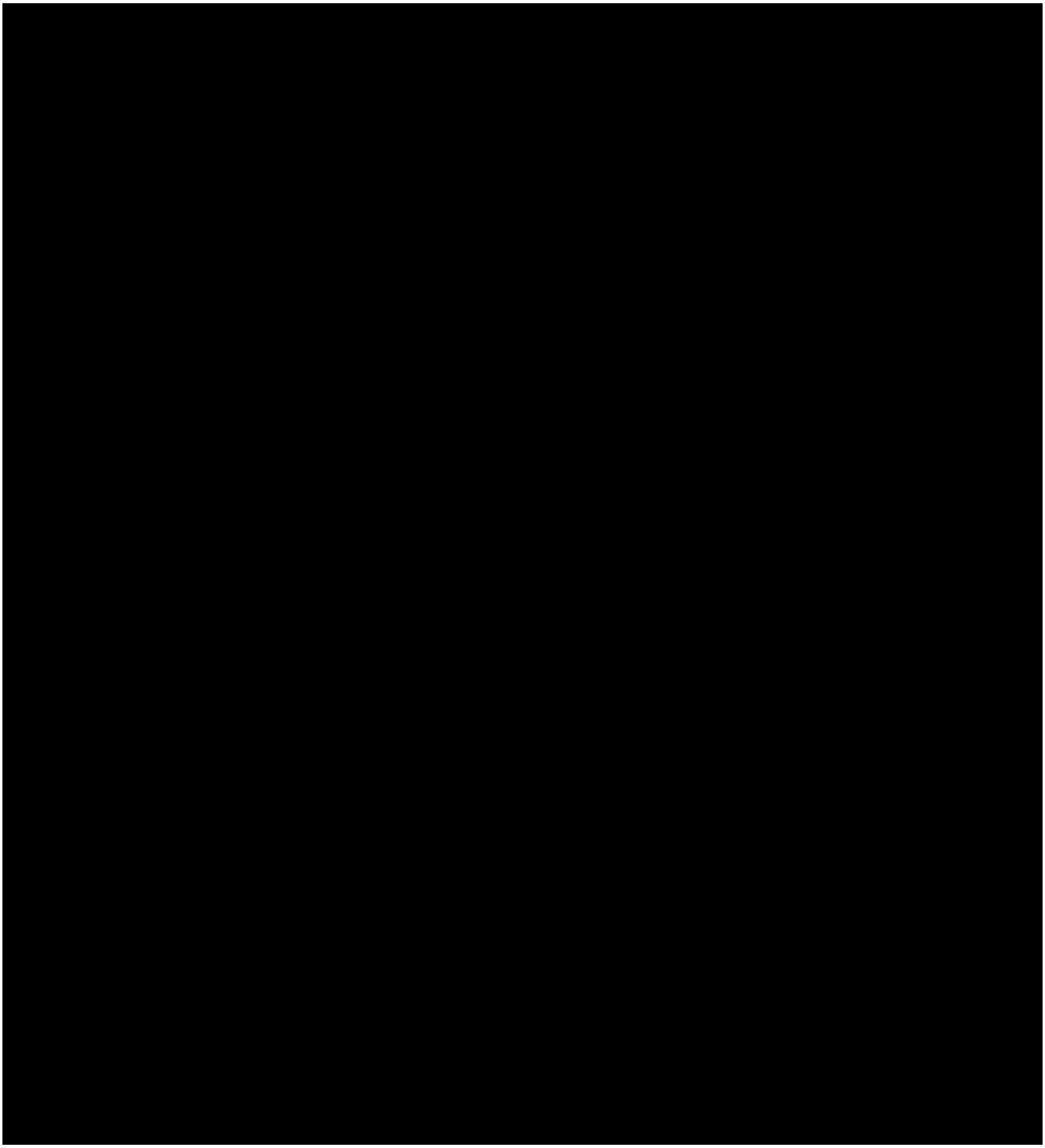


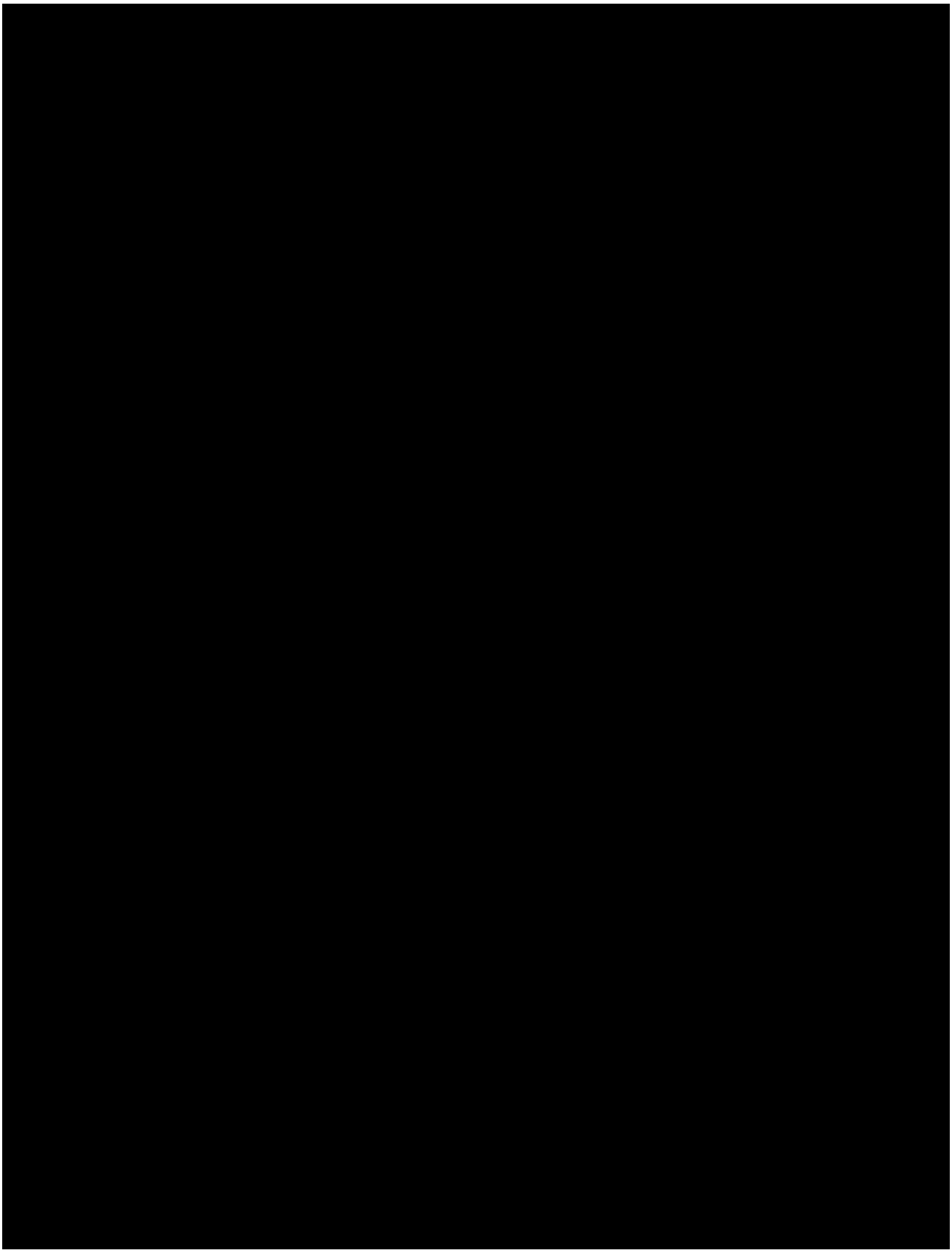
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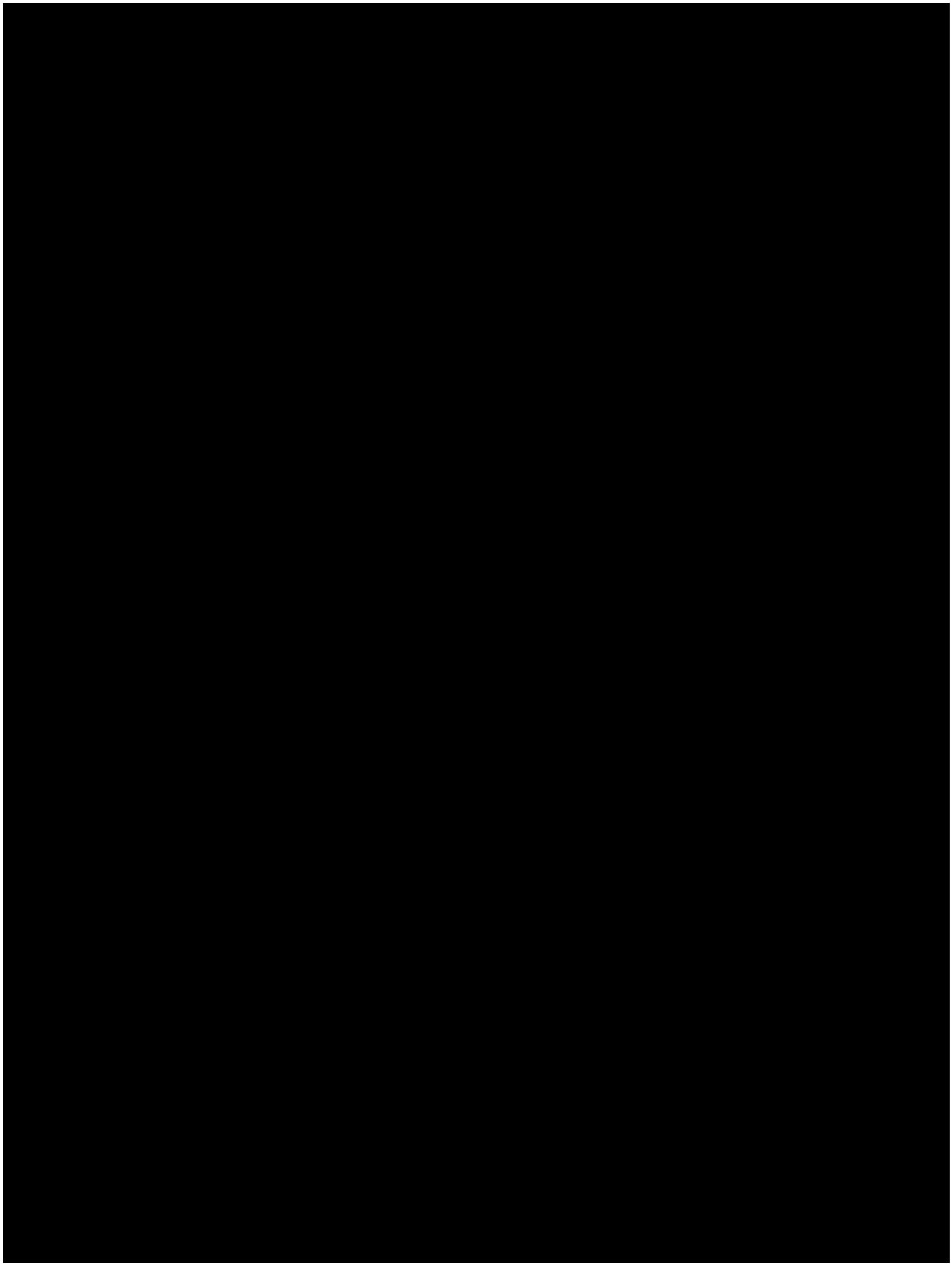


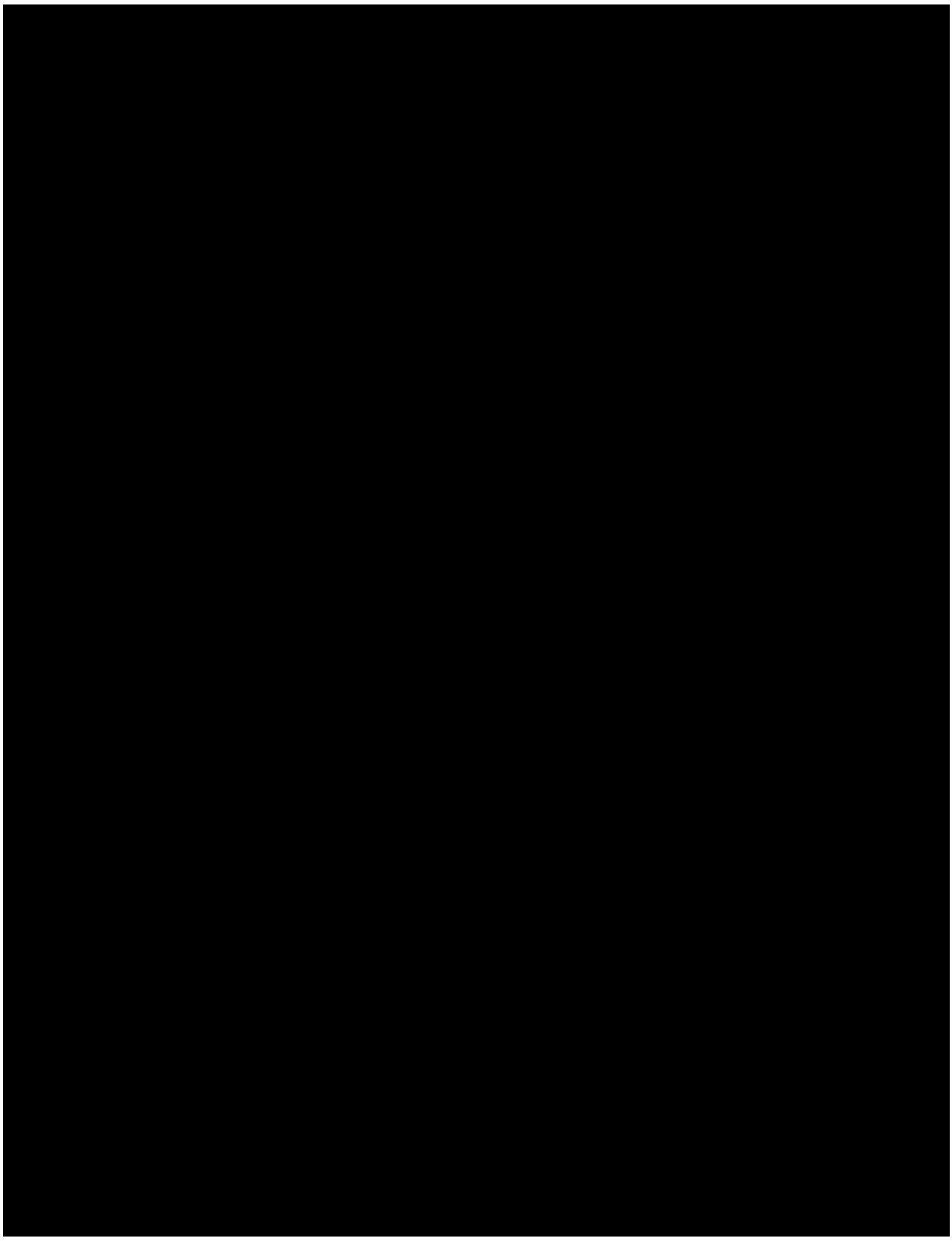
Duke Energy Policy Statement

Credit Policy



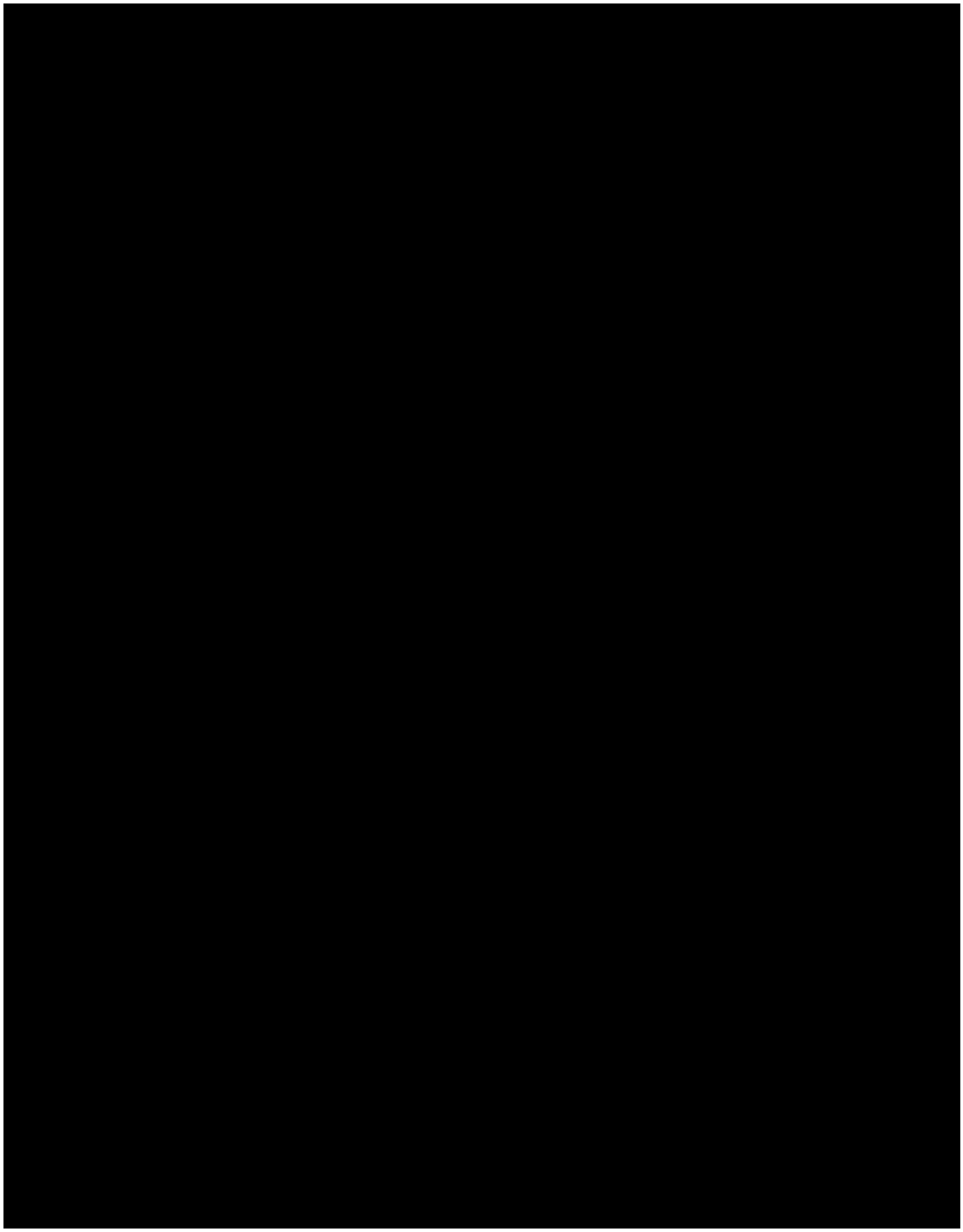








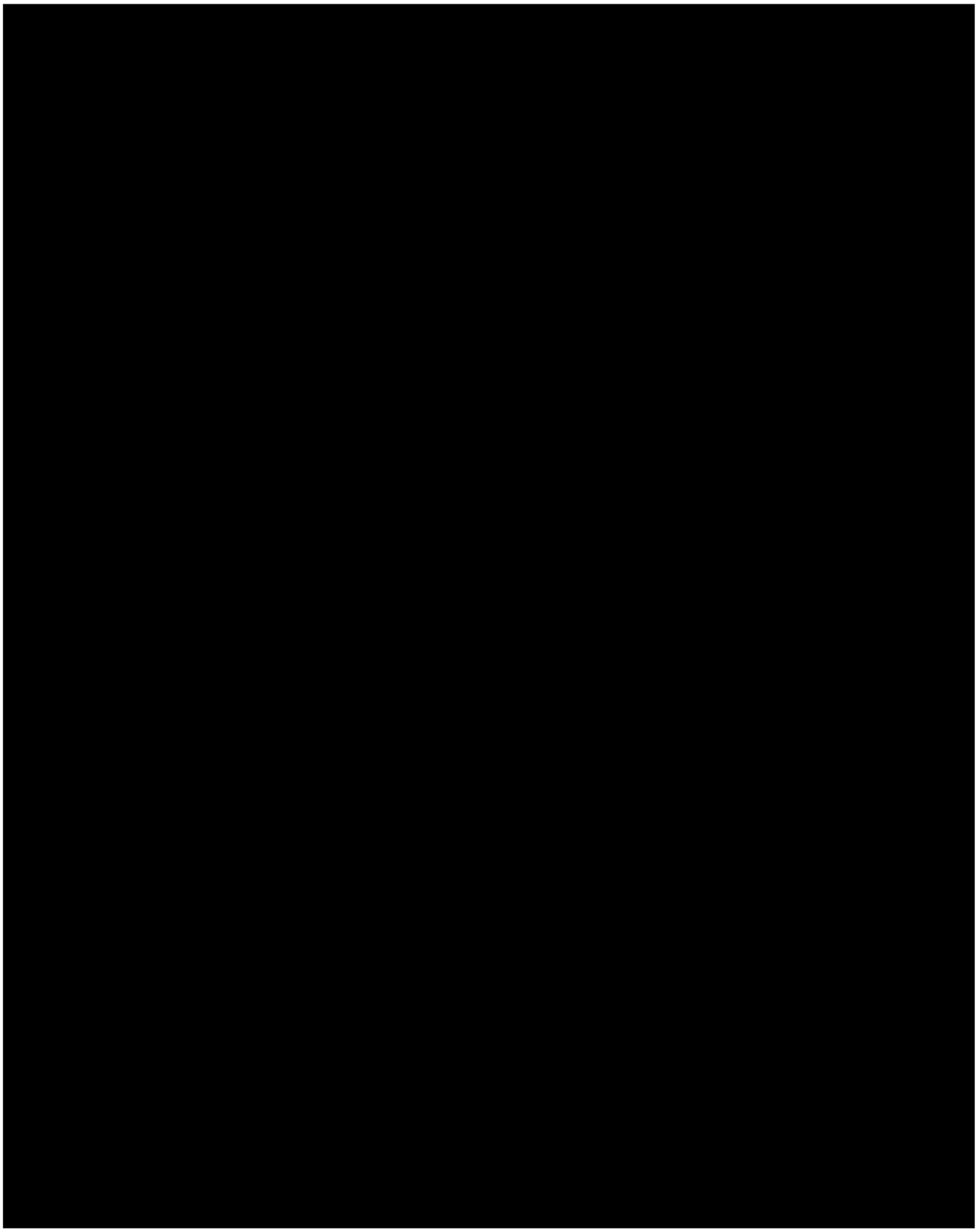
Regulated Utilities Credit Limits (DEF)



Regulated Utilities Credit Limits (DEF)

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Regulated Utilities Credit Limits (DEF)



Regulated Utilities Credit Limits (DEF)

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Regulated Utilities Credit Limits (DEF)

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ENERGY SUPPLY BULK POWER MARKETING & TRADING
DELEGATION OF AUTHORITY

[redacted]

[redacted]

Duke Energy Corporation
Regulated Utilities
Risk Management Control Manual



January 2016

Risk Management Controls and Procedures for Fuels & Systems Optimization and Distributed Energy Resources

Confidential Information

The information contained within this manual is confidential and proprietary to Duke Energy Corporation's Regulated Utilities group, particularly the Fuels & Systems Optimization (FSO) and Distributed Energy Resources (DER) groups, and the various groups supporting these operations as further discussed in this manual. Confidential and proprietary information is a valuable resource, and release of this information to the general public could lead to a competitive disadvantage for Duke Energy Corporation and its subsidiaries ("Duke Energy").

Also, release of this information to the Non-Regulated portions of Duke Energy could result in violation of regulatory rules (e.g., FERC Affiliate Restrictions/Standards of Conduct). Confidential and proprietary information must be protected from unauthorized use, modification, disclosure, or destruction whether intentional or unintentional. Duke Energy employees must also comply with, and periodically acknowledge review of, the Code of Business Ethics policy.

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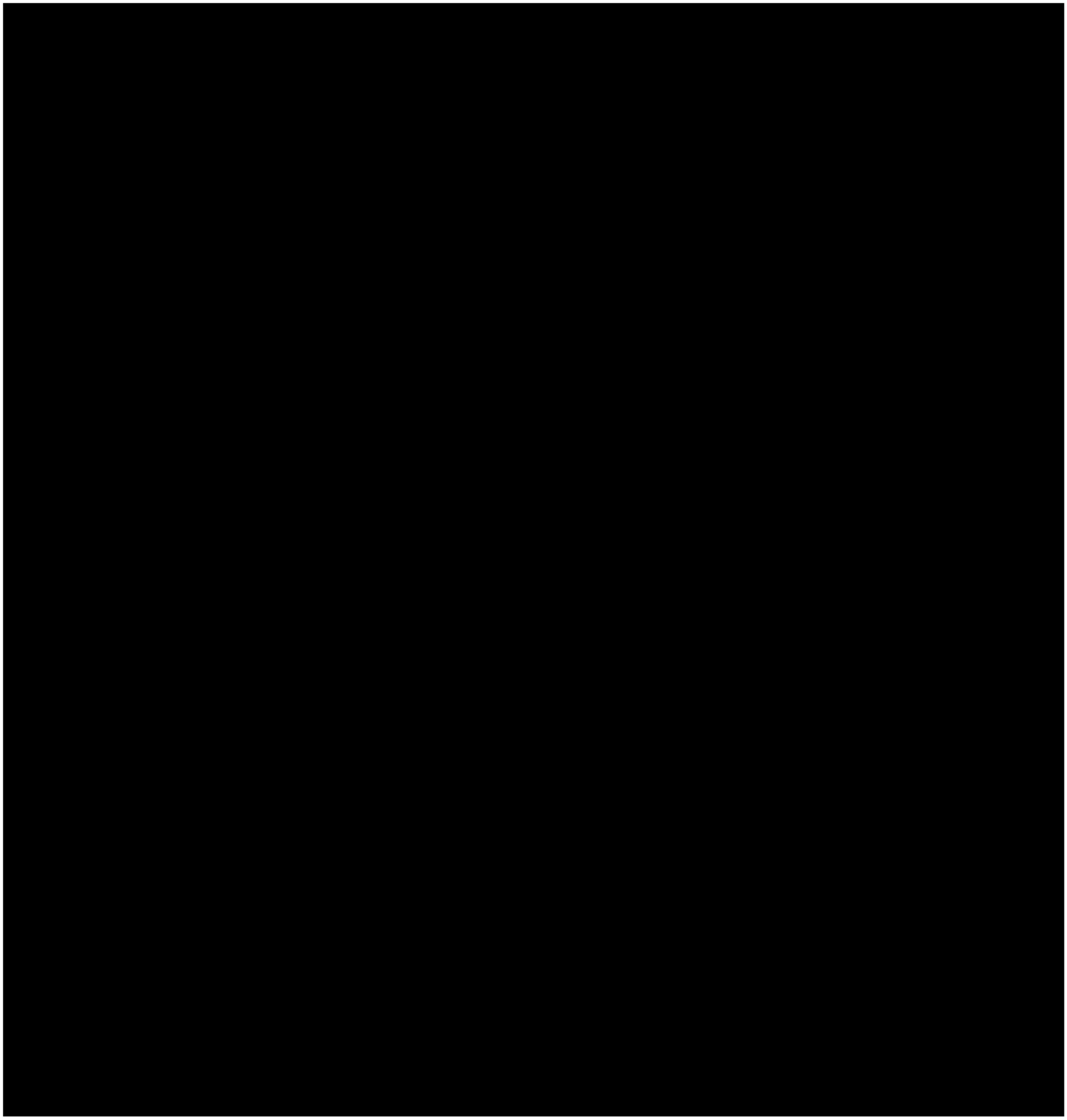
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I. Introduction and Purpose

[redacted]

Risk Management Policies and Procedures

[redacted]



Control Manual Amendments and Approvals



[redacted]

Legal and Regulatory Compliance

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Exception Process

[redacted]

New Employees

[redacted]

Inter-Affiliate Transactions

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[redacted]

II. Concept of Operations

[redacted]

Carolinas (Duke Energy Carolinas & Duke Energy Progress)

[redacted]

[redacted]

Duke Energy Florida

[redacted]

Duke Energy Indiana (DE-IN) & Duke Energy Kentucky (DE-KY)

[redacted]





[redacted]

III. Roles & Responsibilities

Role of Corporate Officers

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Segregation of Function and Ownership

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Role of the Chief Risk Officer

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[redacted]

Role of Global Risk Management

[redacted]

[redacted]

Role of Fuels & Systems Optimization

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Role of Traders

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Role of Regulated Fuels

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Role of Distributed Energy Resources

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Role of Energy Supply Analytics

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Role of Contract Management

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Role of Internal Audit

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Role of Accounting

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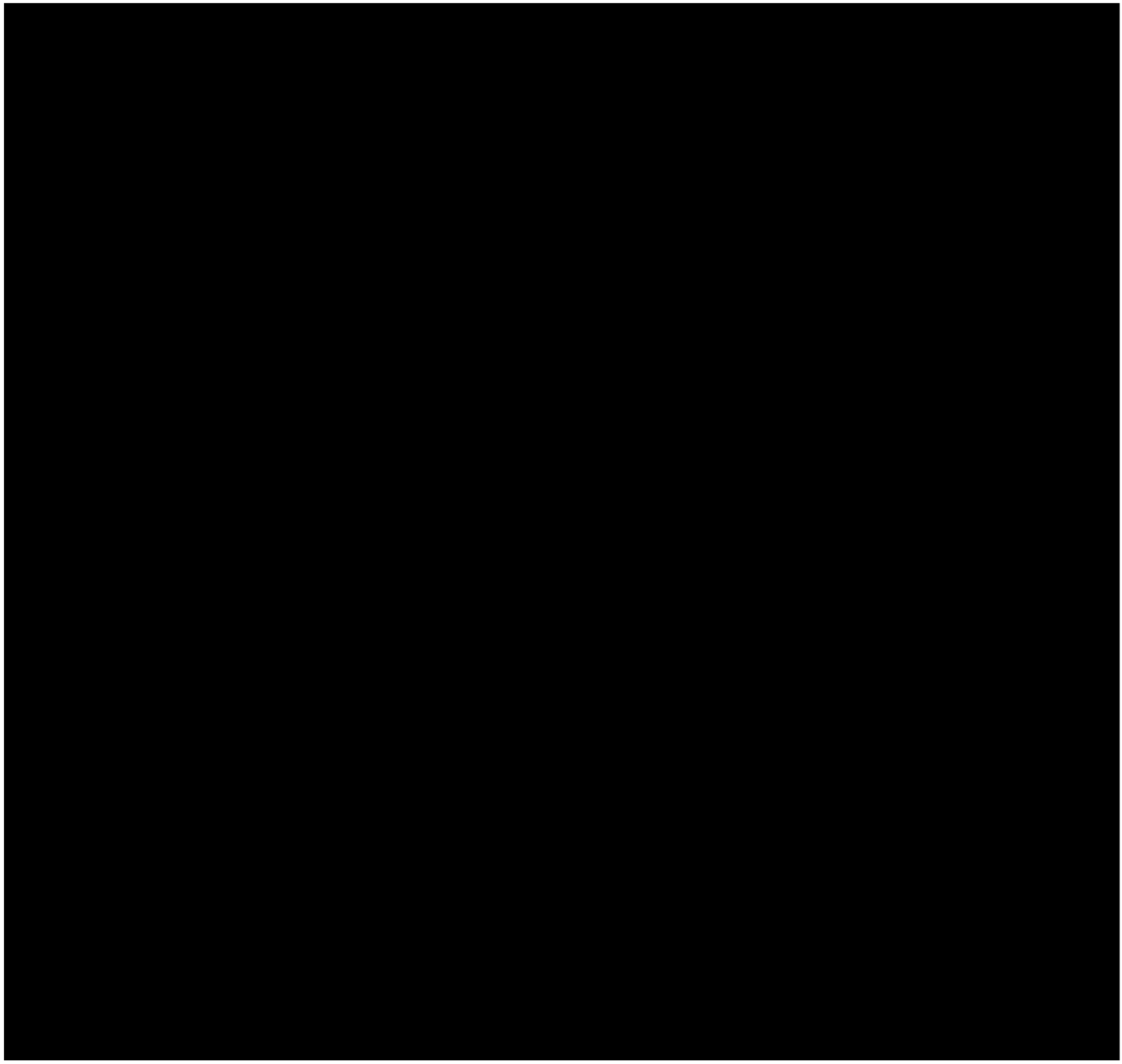
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IV. Control Requirements and Activities

Risk Management

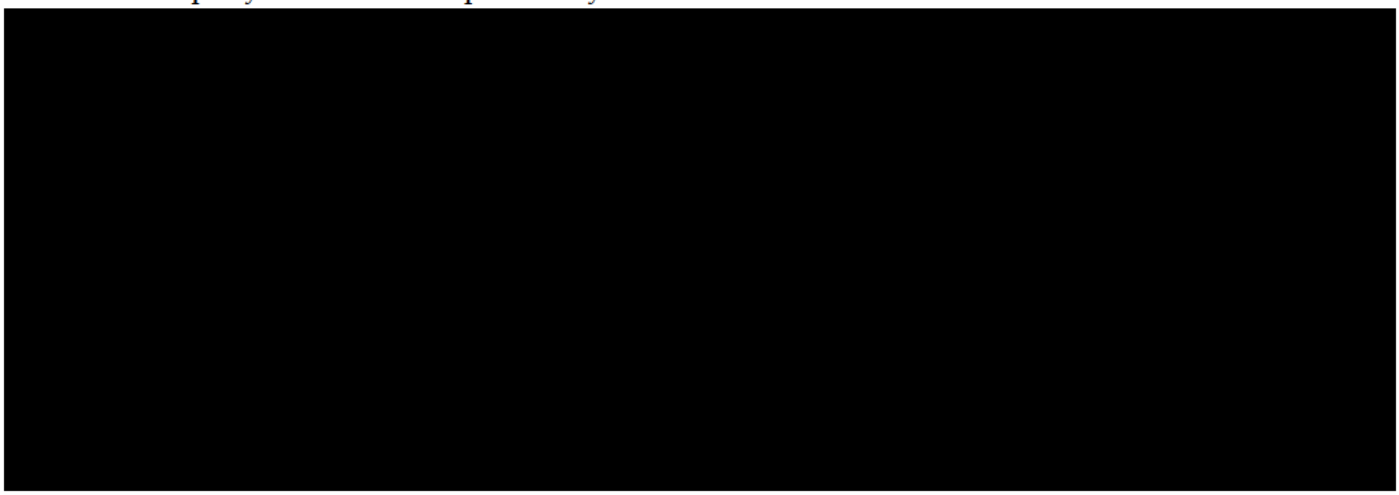
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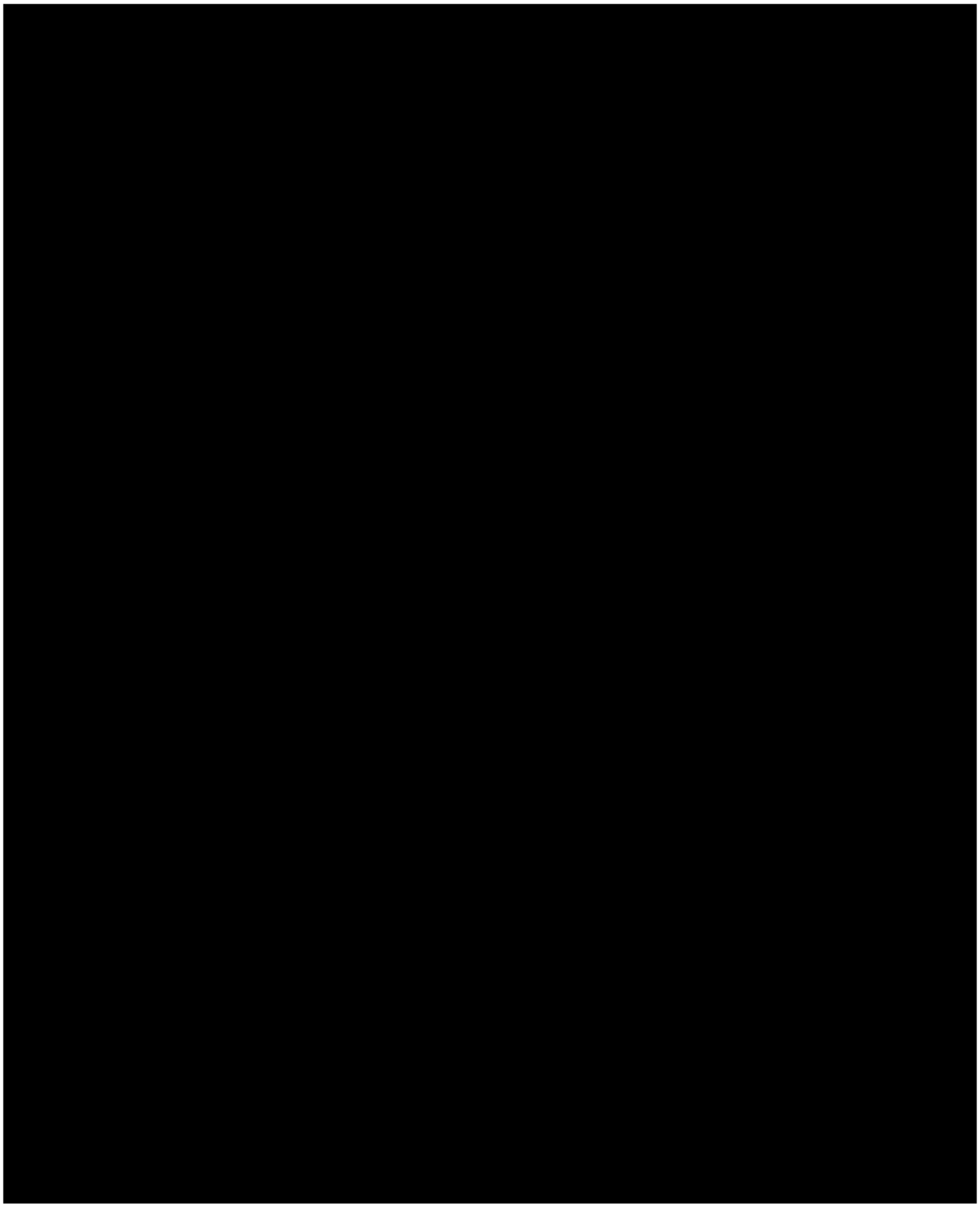
Violations of Risk Control Manual

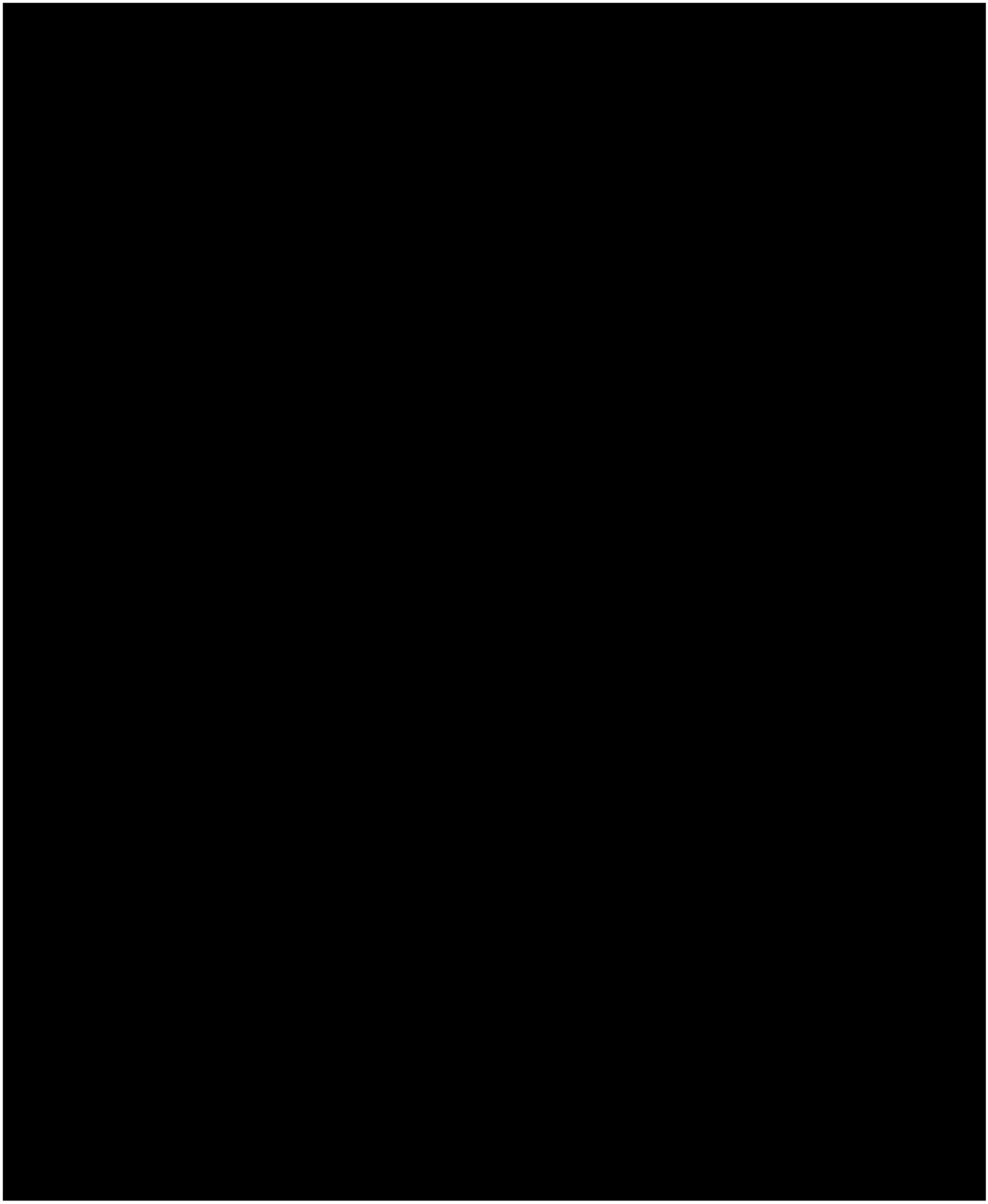


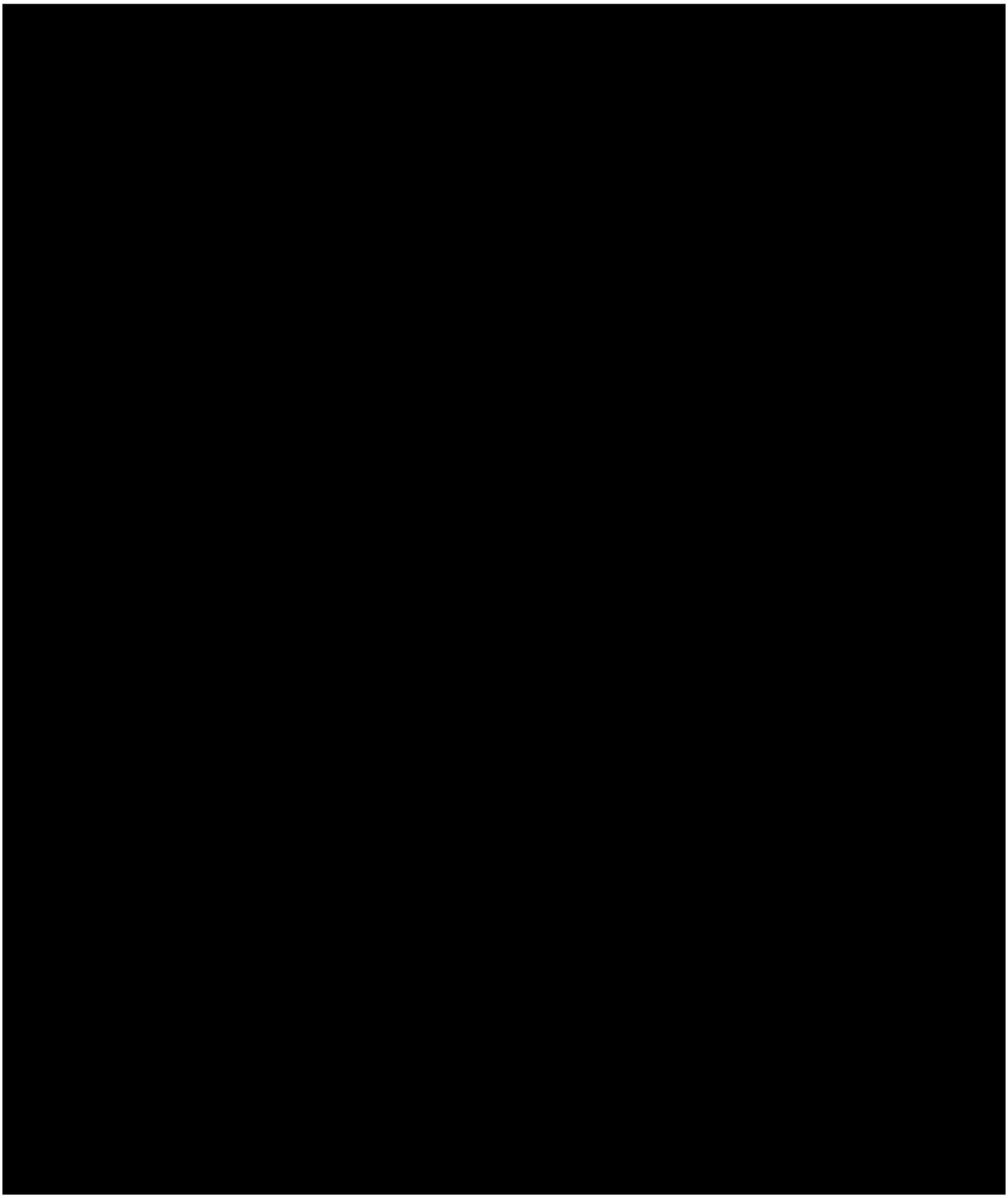


Fuels & Systems Optimization





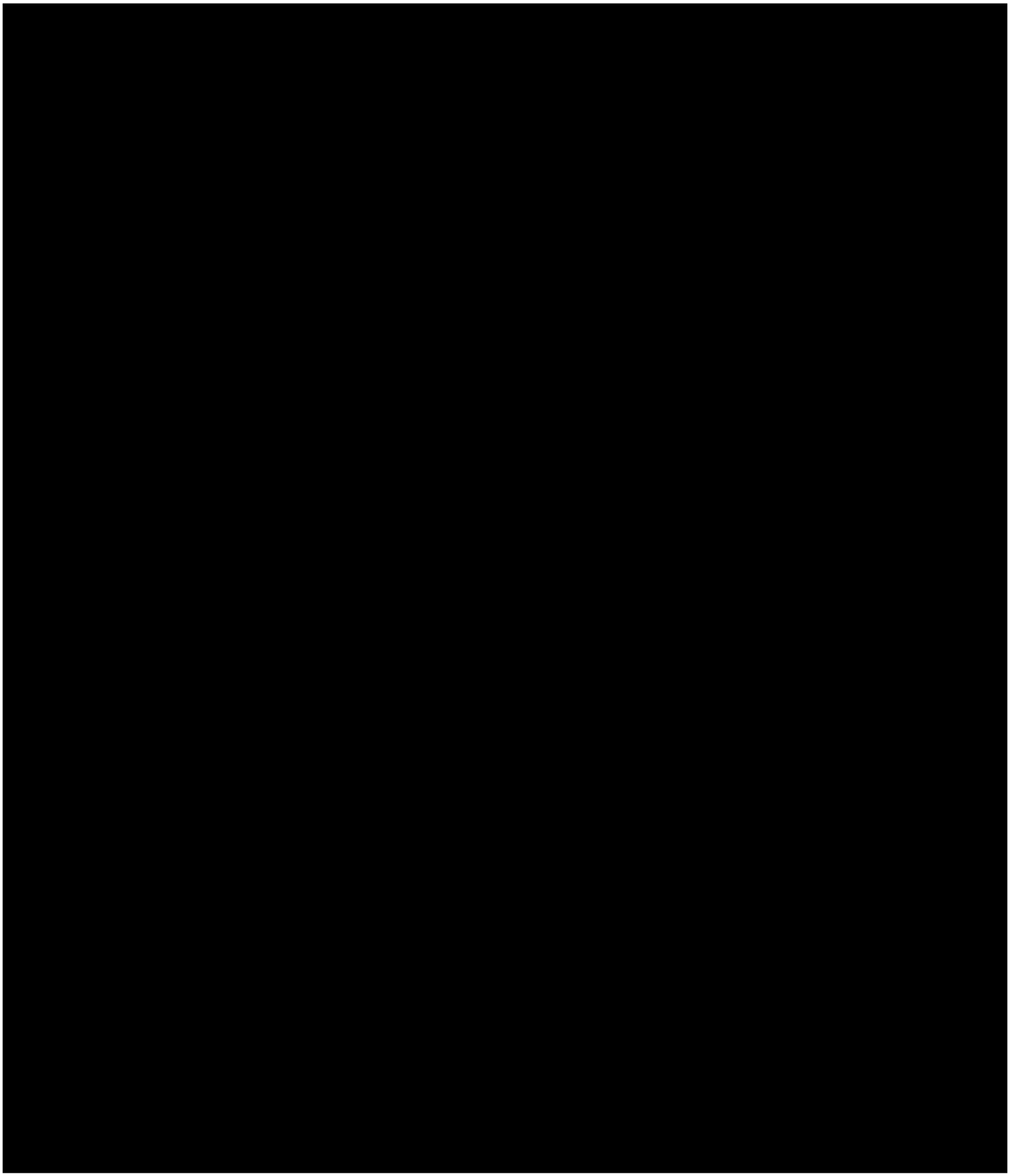




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V. Dodd-Frank

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Appendix A

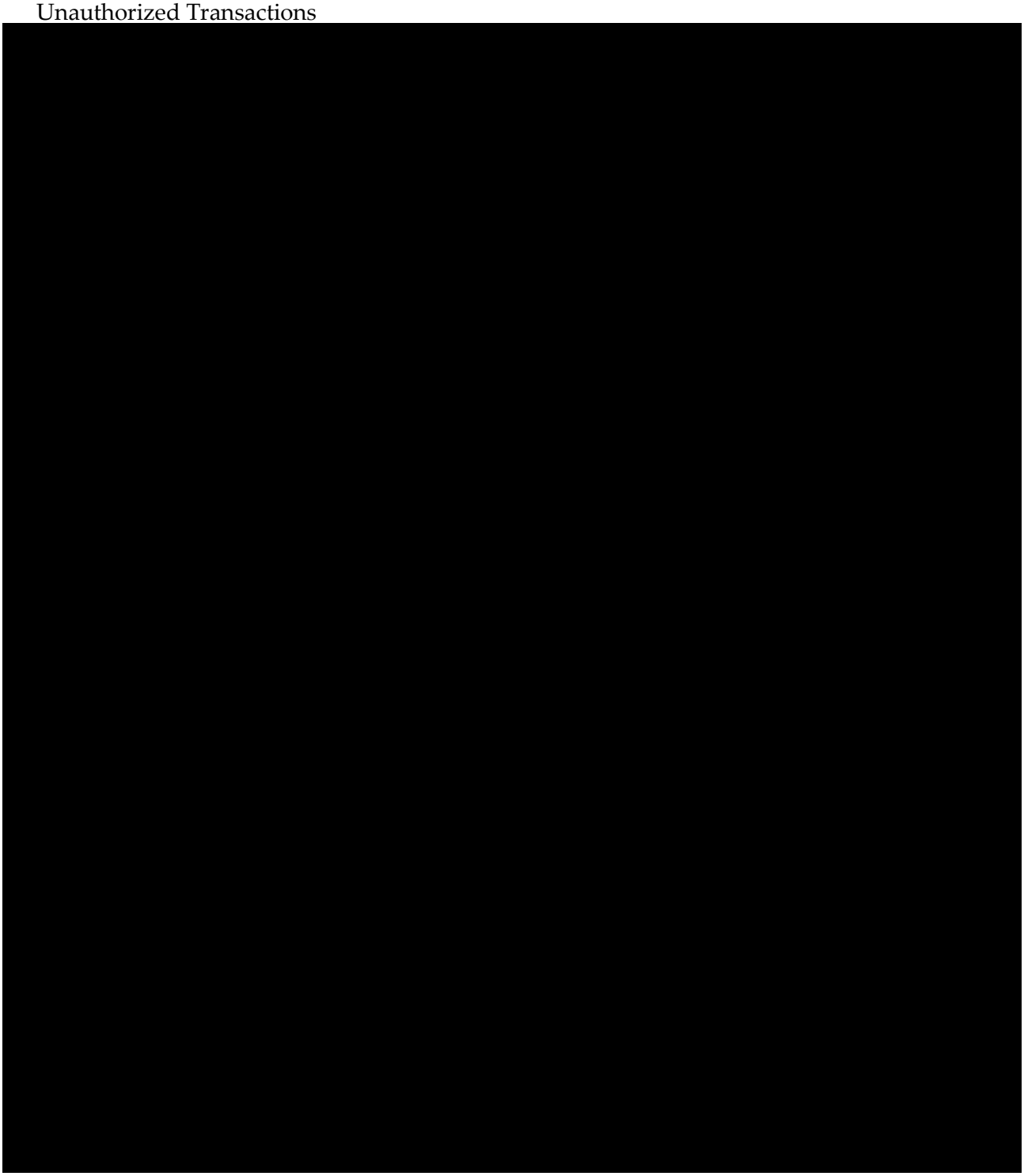
Key Risks

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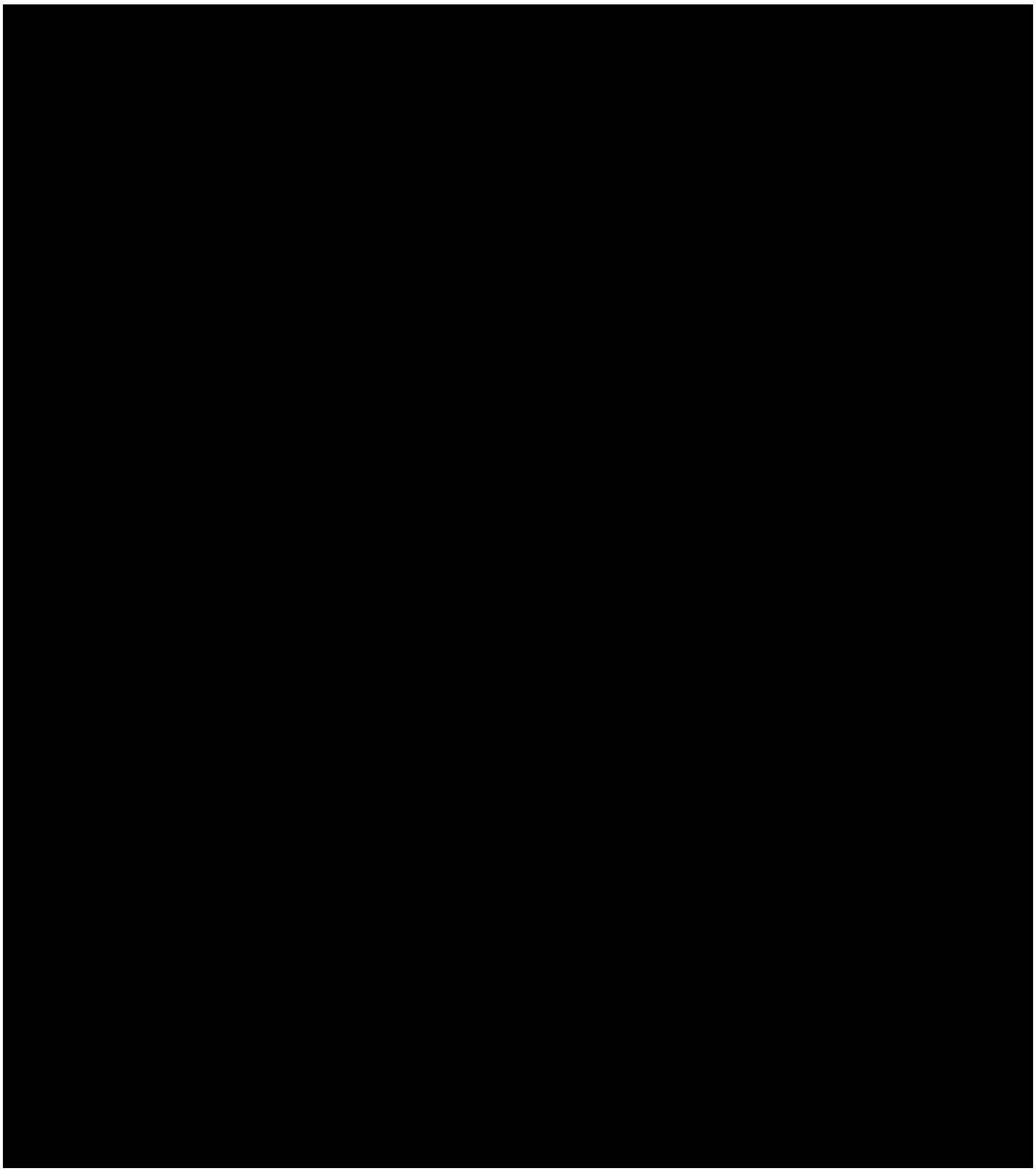
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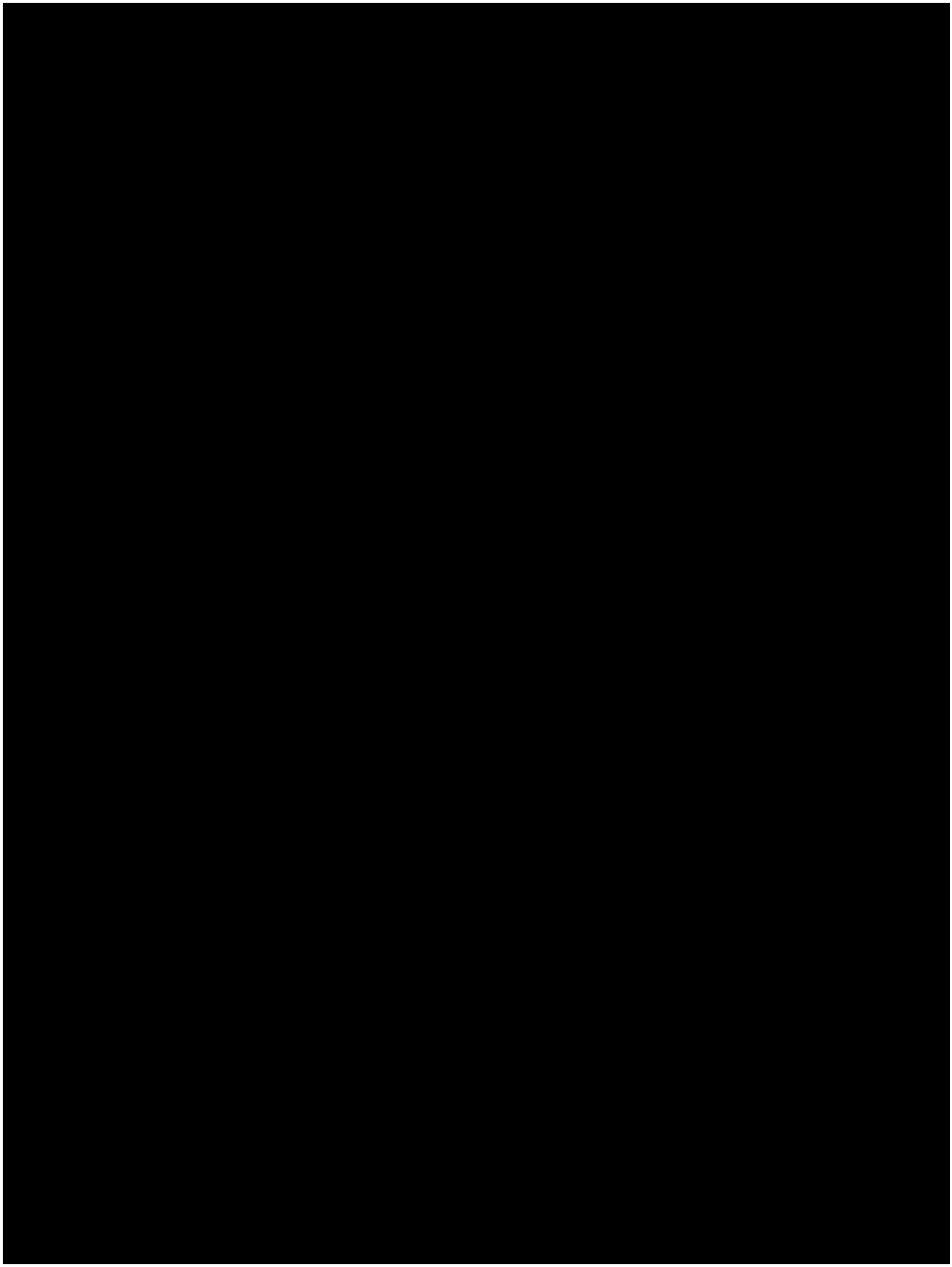
Unauthorized Transactions



Appendix C

Confirmation Activities







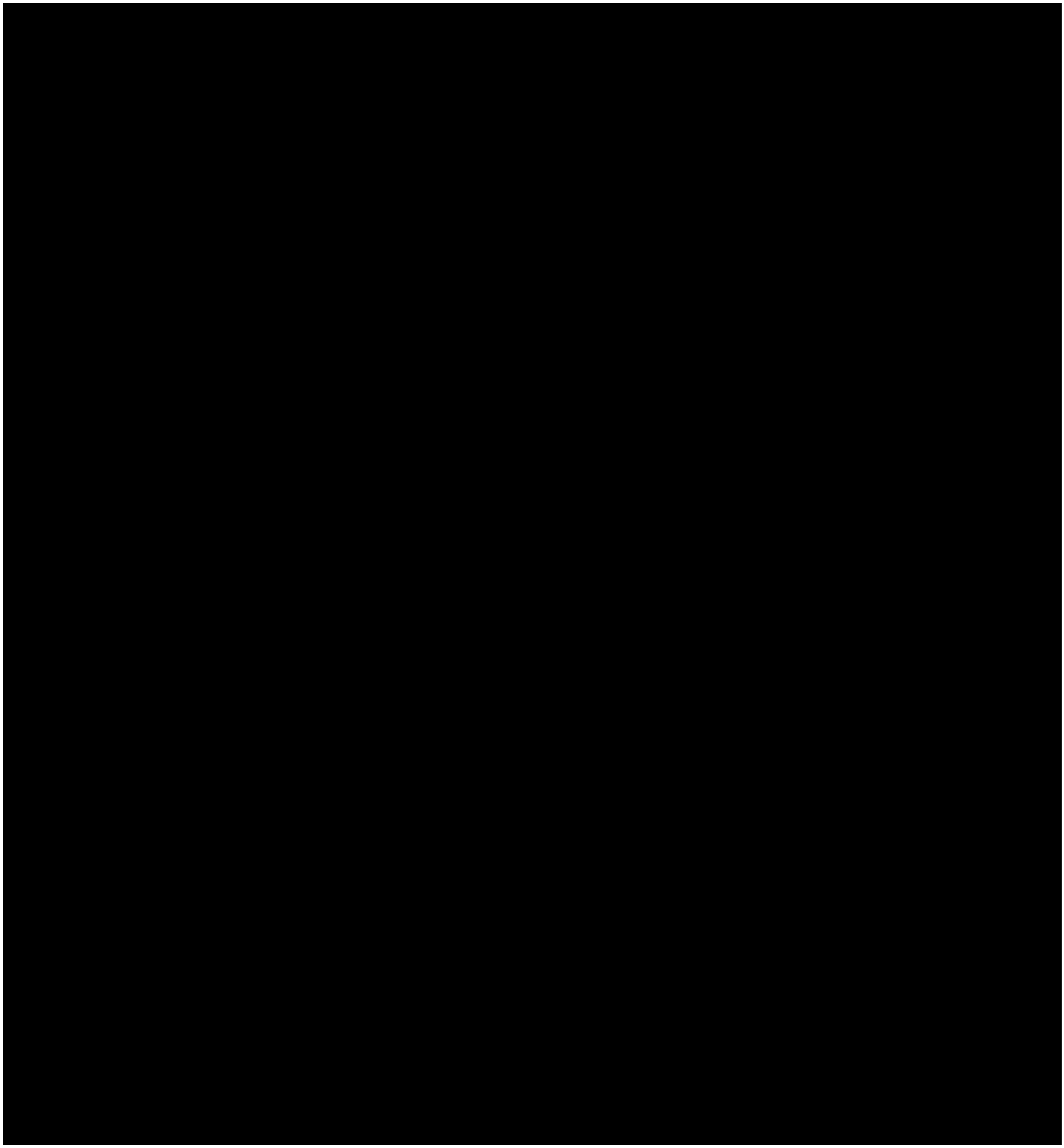
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New Products/Business Activity Approval Process



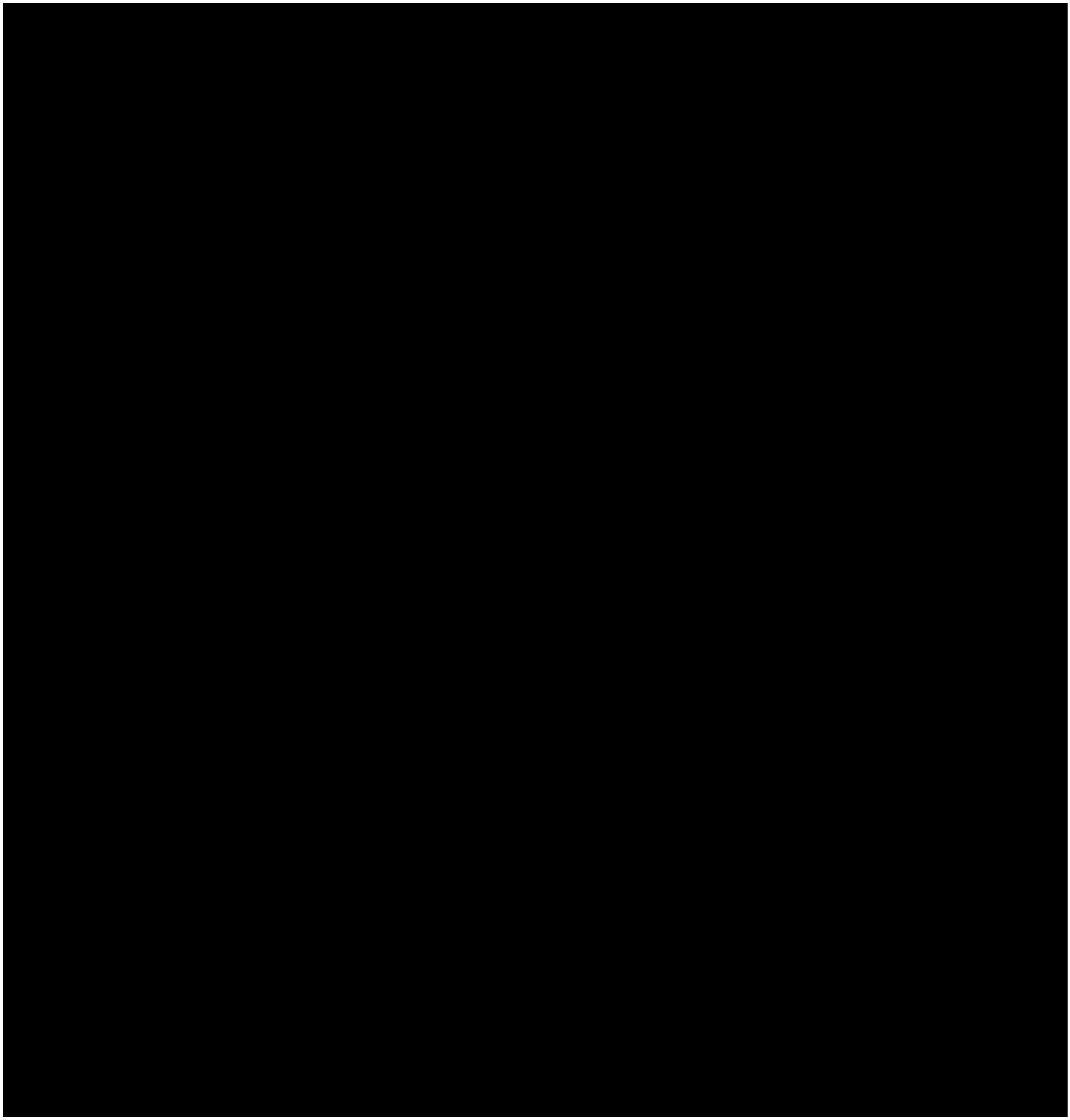
Appendix E

New Product Checklist



Appendix F

Potential Trade Exceptions



Appendix G

Potential Delivery Term Violations



Appendix H

Risk Management Employee Acknowledgment

Employee Name:_____
(Please print)

RISK MANAGEMENT EMPLOYEE ACKNOWLEDGMENT

Global Risk Management has a combination of Policies, Risk Limits, Guidelines and procedures referred to as the "Risk Documents" that contain certain information regarding the governance and procedures of certain Duke Energy activities. Please read and review the appropriate Risk Documents. If you have any questions regarding the Risk Documents, you are to contact your immediate supervisor. It is very important that you understand how the Risk Documents apply to your current position. After reading and understanding the appropriate Risk Documents, please check the Risk Documents read and understood below and sign the Risk Management Employee Acknowledgment as instructed in the last line below.

Check all that apply:

- Duke Energy Commodity Risk Policy (applies across all entities) …… ☐
- Duke Energy Credit Policy (applies across all entities) …… ☐
- Model Review and Approval Process (applies across all entities) ..…… ☐
- Derivative Transaction Policy (applies across all entities) …… ☐
- Duke Energy Regulated Utilities Risk Management Control Manual…… ☐
- Duke Energy Forward Market Price and Volatility Curve Control Manual…… ☐
- Duke Energy Carolinas & Duke Energy Progress Risk Limits …… ☐
- Duke Energy Florida Electric Risk Limits ….…..…… ☐
- Duke Energy Indiana Electric Risk Limits ……..……..…… ☐
- Duke Energy Kentucky Electric Risk Limits……..…… ☐
- Duke Energy Ohio (Reg) Electric Risk Limits …… ☐
- Duke Energy Credit Limits for DEC, DEP, DE-IN, DE-KY..……..…… ☐
- Duke Energy Florida Credit Limits…….....…….. ☐
- Delegation of Authority – Fuels & Systems Optimization …… ☐

I have read the Risk Documents as indicated above outlining Duke Energy's expectations of me. I understand and acknowledge these Risk Documents apply to my position. I acknowledge and agree that it is my responsibility to comply with all aspects of the Risk Documents as well as any future revisions made to the Risk Documents. If I encounter a situation in which I do not know how the Risk Documents applies, I will contact my immediate supervisor.

I further acknowledge and agree that I will contact my immediate supervisor should my responsibilities at Duke Energy change and questions arise regarding the application of the Risk Documents to my new position and/or responsibilities.

I understand and acknowledge that my failure to comply with the Risk Documents will result in corrective action, up to and including termination.

I ACKNOWLEDGE AND UNDERSTAND THAT NEITHER THE RISK DOCUMENTS EMPLOYEE ACKNOWLEDGMENT NOR ANY OF DUKE ENERGY'S POLICIES OR PROCEDURES, INDIVIDUALLY OR TOGETHER, CONSTITUTE A GUARANTEE OF CONTINUED EMPLOYMENT, CREATE A CONTRACT OF EMPLOYMENT OR ALTER THE AT-WILL NATURE OF MY EMPLOYMENT IN ANY WAY.

_____/_____

Employee Signature / Date

_____

Employee Title

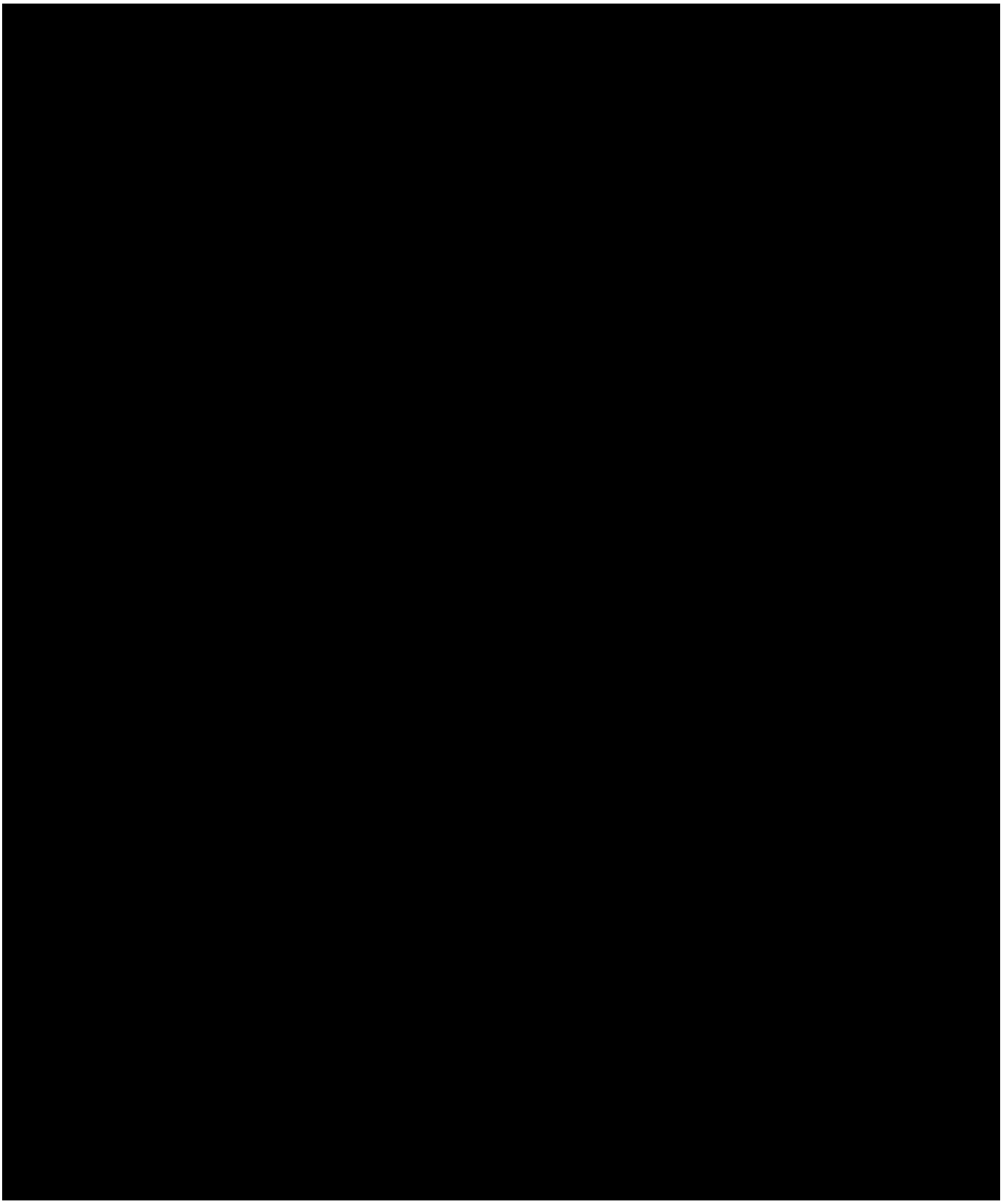
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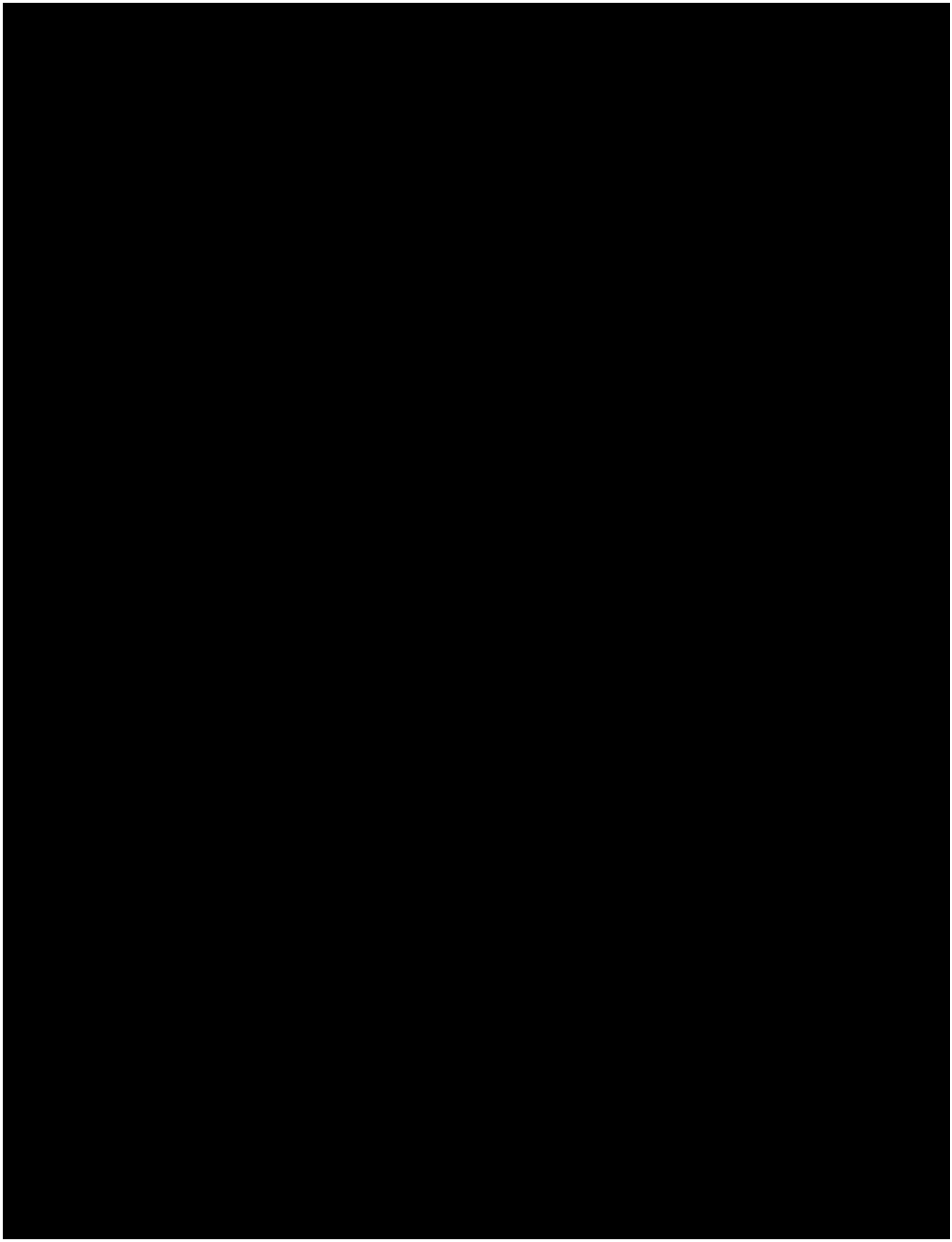
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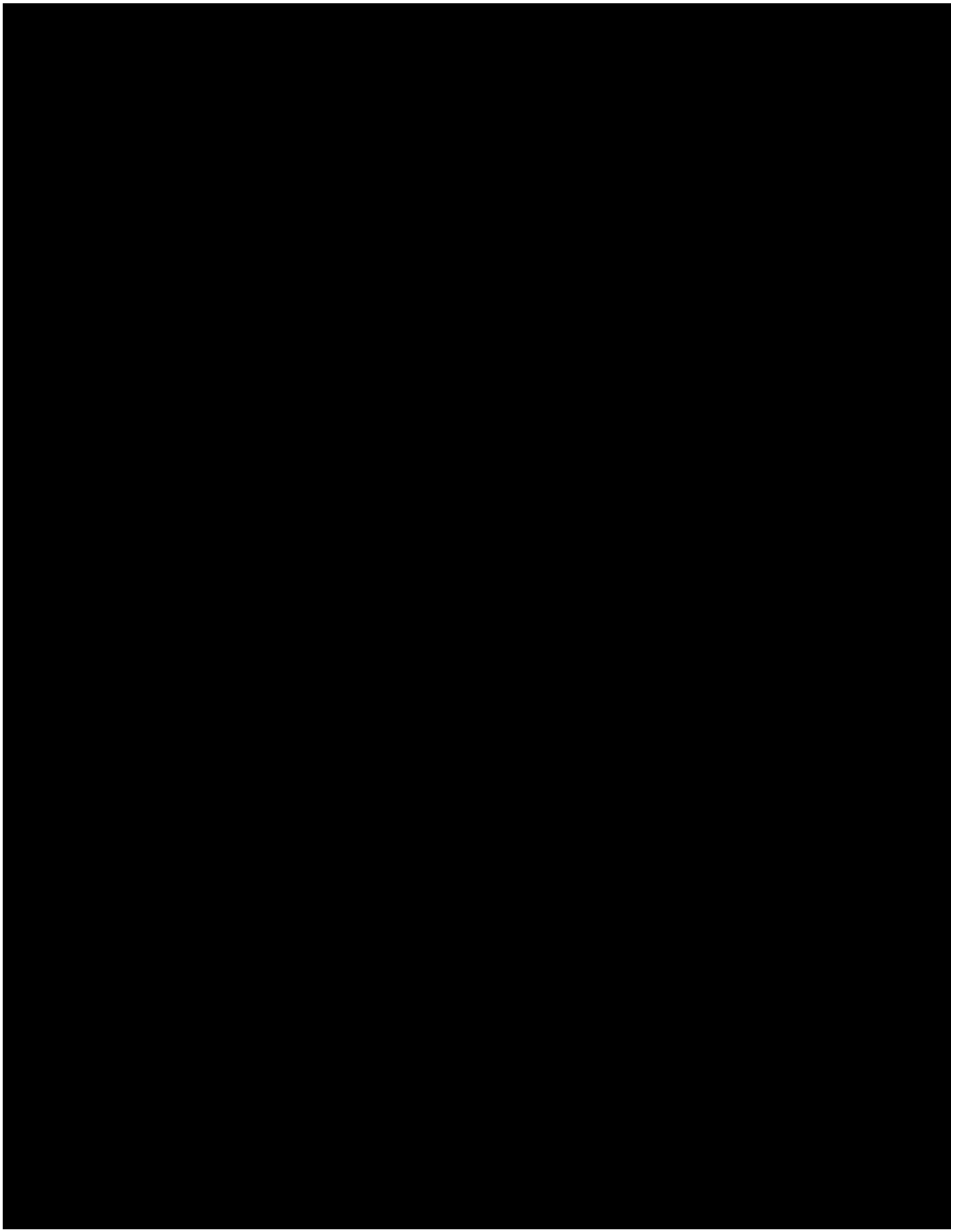
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Appendix I

FERC 741 Officer Certification Process







REDACTED



Appendix H

Risk Management Employee Acknowledgment

Employee Name:_____
(Please print)

RISK MANAGEMENT EMPLOYEE ACKNOWLEDGMENT

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- Duke Energy Regulated Utilities Risk Management Control Manual…… ☐
- Duke Energy Forward Market Price and Volatility Curve Control Manual…… ☐
- Duke Energy Carolinas & Duke Energy Progress Risk Limits …… ☐
- Duke Energy Florida Electric Risk Limits ….…..…… ☐
- Duke Energy Indiana Electric Risk Limits ……..……..…… ☐
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- Delegation of Authority – Fuels & Systems Optimization …… ☐

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_____/_____

Employee Signature / Date

_____

Employee Title

_____

Print Full Name

Appendix I

Attachment J

Company Guidelines and Procedures

Document Title	Document Summary
Approval of Business Transactions Policy	The Approval of Business Transactions (ABT) Policy outlines the minimum reviews and approvals required for the execution of transactions, documents and forms necessary for the conduct of business.
Authority Limit Matrix from the Approval of Business Transactions Policy	Duke approval limits for specific employees for purchase or sale of commodities, storage, transportation or capacity or other sales.
Coal and Emission Reducing Chemicals Procurement Procedure	This policy defines the roles, responsibilities, and requirements of negotiation, execution and administration of contracts for the purchase and transportation of fuel and emission reducing chemicals (e.g., coal, lime, limestone, trona, ammonia, urea, freeze-proofing, railcar lease and maintenance, etc.) within the U.S. Franchised Electric and Gas organization of Duke Energy Corporation (“Duke Energy” or the “Corporation” or the “Company”). Specific topics addressed include required approvals, the sourcing process, documentation, segregation of duties, and standards of business conduct.
Commodity Risk Policy	TThe purpose of the Commodity Risk Policy ("the Policy") is to provide clear and consistent directives in the identification, quantification, management and communication of commodity risk across the Enterprise. This Policy covers all sales or purchases of commodities, storage, transport, capacity or fuel procurement and related services, and contracts with embedded commodity exposure. Approved commodities include both standardized products as well as structured contractual products and must be listed in the Approved Commodities section of the applicable risk limits for each Business Unit.
Constrained Operations Application	This procedure establishes the roles and responsibilities for use of the Constrained Operation Application by System Operations Energy Control Center (ECC) and System Operations Center (SOC) personnel, Fuels and System Optimization (FSO), and Fossil Hydro Operations (FHO) personnel. Specifically, this procedure defines the functions of these organizations and the communications necessary to support the planning and implementation of unit constraints, including testing, maintenance, and derates, in an economic manner, considering margins required for system reliability.
Credit Policy	Extending and monitoring credit to customers and counterparties is integral to all of Duke Energy Corporation's businesses. Global Risk Management (GRM) has established standards of practice related to the management of credit risk across Duke Energy Corporation and its subsidiaries (“Duke Energy”). This policy governs the extension of credit related to wholesale business activity (including fuel procurement), enterprise sourcing (including major construction projects), and other business activities as described herein.
DEF Operating Plan Development and Implementation	This procedure establishes the roles and responsibilities for DEF Fuels and System Optimization (FSO), System Operations (ECC) personnel, and Fossil Hydro Operations. Specifically, this procedure defines the functions of these organizations and the communications necessary to support economic optimization of all resources while considering operational constraints and reserve margins requires for system reliability.
Delegation of Authority Policy	This policy establishes the approval authority limits for all employees within the organization below the Senior Management Committee. Approval authority limits for the Board of Directors, President and Chief Executive Officer (CEO), and Senior Management Committee members are defined in the Approval of Business Transactions (ABT) Policy. Employees based outside of the United States are covered by the Delegation of Authority Policy – International Employees.
Derivative Transactions Governance Policy	Duke Energy companies engage in derivative transactions, including swap transactions, to hedge or mitigate commercial risk. These transactions may be subject to laws in the United States, the European Union, and other countries that are designed to mitigate systemic risk to financial systems, increase transparency, and promote market integrity, among other goals. Duke Energy intends to comply with all such applicable laws and regulations.
Duke Energy Corporation Regulated Utilities Risk Management Control Manual	This document, the Regulated Utilities Risk Management Control Manual (Control Manual), is intended to present a description of the internal control environment and related control procedures for the regulated trading functions including but not limited to power, gas, emissions, coal and renewable energy certficates.
Duke Energy Global Risk Management Credit Delegation Of Authority	This Credit Delegation of Authority (“Credit DOA”) document contains various required credit activities and standards involved in setting credit limits including the delegation of credit authority. It bridges the Credit Policy and evolving market conditions as well as provides guidance for best practices to ensure consistent application across Duke Energy Corporation and its subsidiaries (“Duke Energy”). As such, the Credit DOA may be more frequently reviewed and updated than the Credit Policy. Business Units (“BU”) are required to conform with this Credit DOA in conjunction with the requirements of the Approval of Business Transactions Policy.
Duke Energy Global Risk Management Credit Procedures Manual	The purpose of this Credit Procedures Manual (“Credit Manual”) is to set forth guidelines to help business units and Global Risk Management (GRM) develop consistent procedures throughout the enterprise with regard to measuring, monitoring, and reporting credit risk. It is intended to complement the Credit Policy and Credit Delegation of Authority (DOA), by providing more specific guidance, primarily for GRM personnel assigned to support specific business units.
Duke Energy Supply Bulk Power Marketing & Trading Delegation of Authority	Delegation of Authority approval limits for specific employees

Attachment J

Company Guidelines and Procedures

Document Title	Document Summary
Duke Energy's FERC Compliance Program	Duke Energy's FERC Compliance Program outlines the key regulatory requirements and compliance standards related to the FERC regulations that are applicable to Duke Energy.
Duke Energy's NERC Enterprise Compliance Program	Duke Energy's commitment to operate its business and assets in a manner that ensures the reliability of the North American bulk power system, including compliance with the NERC Reliability Standards
Duke Energy's Standards of Conduct Written Procedures	The Federal Energy Regulatory Commission (FERC) issued Order No. 717 which revised the Standards of Conduct rules adopted in Order No. 2004 that apply to interstate natural gas pipelines and electric utilities ("Transmission Providers"). The Standards of Conduct rules govern the relationship between a Transmission Provider's transmission function employees and its marketing function employees. The Compliance Procedures are applicable to Transmission Providers of the franchised electric utilities of Duke Energy Corporation (collectively, the Franchised Utilities).
FPO Operational Communications	The purpose of this procedure is to establish protocols for routine daily / hourly communications/interaction between Marketing Function Employees (MFEs) within the Fuels and System Optimization (FSO) Department and Transmission Function personnel at the respective Energy Control Centers (ECCs), System Operations Center (SOC) and Hydro Central.
FSO – DEC and DEF Gas Trading Procedure for Off-Premise Transactions	This procedure defines the process in which off-premise gas procurement, scheduling and trading shall be conducted for all the company's gas generation facilities in the Carolinas and in Florida.
FSO - DEF Long-Term Gas Supply RFP Process	The purpose of this process is to outline the Long-Term RFP process by which Duke Energy Florida (DEF) procures competitively priced natural gas to meet its longer-term projected fuel needs at its owned and tolled gas generation facilities in Florida.
FSO – DEF Short-Term Gas Procurement and RFP Procedure	The purpose of this procedure is to outline the Short-Term RFP process by which Duke Energy Florida (DEF) procures competitively priced natural gas to meet its shorter-term projected fuel needs at the company's owned and tolled gas generation facilities in Florida. For clarity: short-term RFP gas procurement activities typically are for monthly, seasonal and annual periods for the current year and the following year for which natural gas supplies are projected to be needed to meet DEF's daily, monthly, seasonal and annual needs at its owned and tolled gas generation facilities. DEF procures a portion of its projected fuel needs through the short-term RFP processes and as needed will procure competitively priced natural gas supply through informal market solicitations based on the specific business opportunities and need. Also, DEF may procure gas on a short-term spot basis for seasonal, monthly, or daily needs based on changing forecast. There may be instances due to timing and business needs that there is an overlap between activities that are defined as the short-term and long-term activities. In following this procedure, it may also be necessary for DEF to have related capacity release activities that need to be followed which are outlined in the FSO - DEF Short-Term Transportation Capacity Procedure (STDP-MKT-FSO-00004).
FSO - DEF Short-Term Transportation Capacity Procedure	This procedure defines the process by which the Trader procures short-term capacity based on projected need and ensures compliance with FERC capacity release regulations.
FSO Long-Term Firm Natural Gas Transportation Process – Florida	This procedure defines the process by which Duke Energy Florida ("DEF") procures reliable and competitively priced long-term firm transportation for DEF for a term of one year or greater to meet projected long-term needs for owned generation facilities and tolled generation facilities where DEF has responsibility for the natural gas supply.
FSO NERC E-Tag for Physical Power Deals	Define process developed to ensure compliance with NERC Interchange (INT) Standards; specifically, those related to the completion and validation of NERC E-Tag electronic documents for physical power transactions. The valid ETag will serve as notice that the Arranged Interchange has been submitted to the Interchange Authority.
FSO –Regulated Oil Procurement Procedure for Off-Premise Transactions	This procedure defines the process in which off-premise oil procurement (physical spot purchase) shall be conducted with a supplier not under current contract, for Duke Energy Florida (DEF), Duke Energy Progress (DEP), Duke Energy Carolinas (DEC), Duke Energy Indiana (DEI) and Duke Energy Kentucky (DEK).
Fuel and System Optimization (FSO) DEF Emissions Trading Process & Procedure Check List	The Fuel and System Optimization (FSO) department which manages SO2 & NOx allowance under Cap and Trade programsCap and Trade programs as well as other REC related programs for Duke Energy Florida's(DEF) generation system as applicable as applicable. The purpose of managing these emissions credits for DEF is to ensure compliance with any Federal EPA cap and trade regulations as well as any additional regulation adopted by State or Federal legislation.
Fuel and System Optimization (FSO) DEF Oil Procurement Process	The purpose of this process is to ensure that appropriate volumes of competitively priced fuel oil and transportation are available for Duke Energy Florida (DEF) native load oil-fired generation in order to meet peaking and baseload fuel oil requirements, utilizing approved processes and procedures. The purpose of this DEF Long-Term Oil Procurement & RPF Process is the following: As needed establish "requirements type" fuel oil supply commitments for No. 2 fuel oil of up to one year or longer , with the ability to renew for additional periods if there are no material changes to contract terms, pricing, fuel specifications or overall fuel need. Balance fuel oil procurement under term contracts with spot contracts. Define the process to solicit, evaluate, and recommend fuel oil transactions to meet DEF's fuel oil requirements

Attachment J

Company Guidelines and Procedures

Document Title	Document Summary
Fuel and System Optimization (FSO) Spot Market DEF Oil Procurement Process	To ensure that appropriate volumes of competitively priced fuel oil are available for Duke Energy Florida (DEF) native load oil-fired generation in order to meet peaking and base load fuel oil requirements, utilizing approved processes and procedures. The purpose of this Spot Market DEF Oil Procurement Process is to describe the process to acquire fuel oil in addition to what is available under long term contracts.
Fuel Oil Emergency Procedure - PEF	Gas, Oil, and Emissions within FSO are responsible for maintaining fossil, combustion turbine (CT) and combined-cycle (CC) power plant fuel oil inventories through ordering of fuel oil to be delivered to each DEF plant. This procedure outlines the process required when a fuel oil emergency occurs.
Fuels and Power Optimization Electronic Futures Exchange Management Procedures	Electronic trading platform for energy trading and price discovery.
Generating Unit Maintenance Scheduling	This procedure establishes the process for the development and revision of the Generating Unit Maintenance Schedule (GMS). The GMS process focuses on mid-term optimization for system economics, market opportunities, and craft resources given necessary constraints for system reserve levels, budget, and regulatory constraints. GMS revision process includes the semi-annual optimization and Outage Change Request (OCR) processes.
GenTrader Schedule of Authorities	The purpose of this document is to define the responsibilities of Portfolio Management (PM), and Information Technology (IT) positions related to management and use of the Fuels & System Optimization (FSO) GenTrader (GT) system.
GenTrader Usage Procedure	The purpose of this document is to describe the procedures to be followed when using the Fuels & System Optimization (FSO) GenTrader (GT) system used by FSO Portfolio Management (PM) groups and related downstream or support users.
Model Review and Approval Process	Model risk, the risk originating from using models for valuation and hedging, can be significant for any company with exposure to complex assets and financial positions. At Duke Energy, the vast majority of positions are marked-to-model. Very few positions are truly marked-to-market; that is, liquid market prices are seldom available. As such, model risk becomes extremely important. Model risk may be thought of as originating from three sources: 1) poor or incorrect modeling, including input estimation errors and poor data, 2) trade limitations such as lack of liquidity and transaction costs, and 3) improper use of an otherwise valid model. In such a situation, the review or vetting of models and their use becomes crucial to the business as a way of reducing model risk. This document is a description of the review process at Duke Energy.
Operational Post Analysis and Transaction Costing Process	This procedure establishes the process for Operational Post Analysis and after-the-fact costing (Recosting) of excess generation sales and economy purchases.
Regulated Utilities Credit Limits	This document contains guidance for compliance with the limits applicable to Duke Energy Florida's regulated wholesale generation activities, and other approved activities within the regulated business as described herein.
Regulated Utilities Risk Limits	This document contains the limits applicable to Duke Energy Florida (and its successor), including regulated wholesale generation activities, and other approved activities within the Regulated Utilities business that entail some form of commodity price risk as described herein.

Note: These policies and procedures are as of April 26, 2016

REDACTED

Attachment A

Duke Energy Florida, Inc.
Order No. PSC-08-0316-PAA-EI
Witness: McCallister
Exhibit No. (JM-2P)

Hedging Instrument	Fuel Type	Total January through July 2016 Volume Hedged		Avg Period of Hedge	Total Savings/(Cost) on Hedges
OTC Financial Instruments	Natural Gas	[redacted]	mmbtu's	daily	($114,926,553)
OTC Financial Instruments	Natural Gas - Storage		mmbtu's	daily	$2,250
OTC Financial Instruments	Light Oil - River Barge		gallons	month	$86,537
					($114,837,766)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 11
PARTY: DUKE ENERGY FLORIDA, LLC – (DIRECT)
DESCRIPTION: Joseph McCallister JM-2P

Attachment B

Duke Energy Florida
Natural Gas and Oil Hedging Detail
As of 7/31/2016

REDACTED

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-16	[redacted]						17,385,600	[redacted]			
Feb-16							16,302,300				
Mar-16							18,850,300				
Apr-16							18,904,400				
May-16							24,722,000				
Jun-16							24,413,900				
Jul-16							26,459,200				See Note 1
YTD	($114,926,553)	$0	($114,926,553)	83,502,500	0	83,502,500	147,037,700	57%	100%	0%	See Note 2

Natural Gas Storage											
	Savings/(Cost) on Hedges			Hedged Volumes (MMBtu's)							
Year	Financial	Physical	Total	Financial	Physical	Total Hedged	Injections	Hedged Injections	% Hedged with Financial	% Hedged with Physical	
Jun-16	$2,250	$0	$2,250	[redacted]	0	[redacted]	250,000	[redacted]	100%	0%	
YTD	$2,250	$0	$2,250		0		250,000		100%	0%	

Heating Oil - River Barge - Fuel Surcharge Hedges											
	Savings/(Cost) on Hedges			Hedged Volumes (Gallons)							
Year	Financial	Physical	Total	Financial	Physical	Total Hedged	Estimated Exposure	Hedged Exposure	% Hedged with Financial	% Hedged with Physical	
Jan-16	[redacted]						768,155	[redacted]			
Feb-16							758,592				
Mar-16							752,321				
Apr-16							854,056				
May-16							779,496				
Jun-16							461,517				
Jul-16							354,594				
YTD	$86,537	$0	$86,537	2,394,000	0	2,394,000	4,728,731	51%	100%	0%	See Note 2

Note 1: Actual burns for periods January 2016 through June 2016. July 2016 burn numbers are considered estimates subject to minor adjustments based on actual bookings.

Note 2: Based on actual fuel burns for January 2016 through June 2016, and forecasted fuel burns and estimated fuel surcharge exposures for the balance of 2016, DEF is currently within all of the hedging targets established in the 2016 Risk Management Plan.

Attachment B

DEF Gas Hedging Status
REDACTED

As of July 31, 2016

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	1/1/2016	3328129	BKMONTREAL	NYMEX NG L1D	Henry Hub			$2.3720			
Financial	Financial Option	Put	1/1/2016	3328129	BKMONTREAL	NYMEX NG L1D	Henry Hub			$2.3720			
Financial	Financial Option	Call	1/1/2016	3331417	Morgan Stanley E	NYMEX NG L1D	Henry Hub			$2.3720			
Financial	Financial Option	Put	1/1/2016	3331417	Morgan Stanley E	NYMEX NG L1D	Henry Hub			$2.3720			
Financial	Financial Option	Call	1/1/2016	3339455	Morgan Stanley E	IFERC	Henry Hub			$2.3800			
Financial	Financial Option	Put	1/1/2016	3339455	Morgan Stanley E	IFERC	Henry Hub			$2.3800			
Financial	Financial Option	Call	1/1/2016	3344766	MerrilL ynchCom E EM	IFERC	Transco Zone 4			$2.4000			
Financial	Financial Option	Put	1/1/2016	3344766	MerrilL ynchCom E EM	IFERC	Transco Zone 4			$2.4000			
Financial	Financial Option	Call	1/1/2016	3347636	Citigroup Energy E	NYMEX NG L1D	Henry Hub			$2.3720			
Financial	Financial Option	Put	1/1/2016	3347636	Citigroup Energy E	NYMEX NG L1D	Henry Hub			$2.3720			
Financial	Financial Option	Call	1/1/2016	3348334	BKMONTREAL	NYMEX NG L1D	Henry Hub			$2.3720			
Financial	Financial Option	Put	1/1/2016	3348334	BKMONTREAL	NYMEX NG L1D	Henry Hub			$2.3720			
Financial	Financial Option	Call	1/1/2016	3352226	Morgan Stanley E	NYMEX NG L1D	Henry Hub			$2.3720			
Financial	Financial Option	Put	1/1/2016	3352226	Morgan Stanley E	NYMEX NG L1D	Henry Hub			$2.3720			
Financial	Financial Option	Call	1/1/2016	3354168	Scotia Bank	NYMEX NG L1D	Henry Hub			$2.3720			
Financial	Financial Option	Put	1/1/2016	3354168	Scotia Bank	NYMEX NG L1D	Henry Hub			$2.3720			
Financial	Financial Swap		1/1/2016	3224926	Morgan Stanley E	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3224928	MerrilL ynchCom E EM	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3224929	MerrilL ynchCom E EM	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3225039	Morgan Stanley E	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3225039	Morgan Stanley E	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3225040	JPMorganChase Bank E	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3225041	MerrilL ynchCom E EM	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3225042	Morgan Stanley E	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3225043	Citigroup Energy E	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3225046	Morgan Stanley E	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3225047	JPMorganChase Bank E	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3225056	JPMorganChase Bank E	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3225060	Macquarie Bank Ltd	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3225068	Citigroup Energy E	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3225069	Citigroup Energy E	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3225071	Morgan Stanley E	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3225088	BKMONTREAL	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3225107	JPMorganChase Bank E	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3225120	Morgan Stanley E	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3225202	BKMONTREAL	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3225203	JPMorganChase Bank E	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3225285	Macquarie Bank Ltd	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3226328	JPMorganChase Bank E	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3226334	JPMorganChase Bank E	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3226373	BKMONTREAL	IFERC	Columbia Gulf			$2.3000			
Financial	Financial Swap		1/1/2016	3226378	BKMONTREAL	IFERC	Transco Zone 4			$2.4000			
Financial	Financial Swap		1/1/2016	3226447	JPMorganChase Bank E	IFERC	Transco Zone 4			$2.4000			
Financial	Financial Swap		1/1/2016	3226554	Macquarie Bank Ltd	IFERC	Transco Zone 4			$2.4000			

Attachment B

Financial	Financial Swap		1/1/2016	3226563	JPMorganChase Bank E	IFERC	Transco Zone 4	[redacted]	$2.4000	[redacted]	
Financial	Financial Swap		1/1/2016	3226566	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.4000		
Financial	Financial Swap		1/1/2016	3226569	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.4000		
Financial	Financial Swap		1/1/2016	3226754	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.4000		
Financial	Financial Swap		1/1/2016	3226790	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.4000		
Financial	Financial Swap		1/1/2016	3226796	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.3800		
Financial	Financial Swap		1/1/2016	3226801	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.4000		
Financial	Financial Swap		1/1/2016	3226803	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.4000		
Financial	Financial Swap		1/1/2016	3238365	Citigroup Energy E	IFERC	Henry Hub		$2.3800		
Financial	Financial Swap		1/1/2016	3240195	BKMONTREAL	IFERC	Henry Hub		$2.3800		
Financial	Financial Swap		1/1/2016	3243801	BKMONTREAL	IFERC	Henry Hub		$2.3800		
Financial	Financial Swap		1/1/2016	3251815	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.4000		
Financial	Financial Swap		1/1/2016	3257541	Citigroup Energy E	IFERC	Columbia Gulf		$2.3000		
Financial	Financial Swap		1/1/2016	3269357	JPMorganChase Bank E	IFERC	Columbia Gulf		$2.3000		
Financial	Financial Swap		1/1/2016	3286345	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.3720		
Financial	Financial Swap		1/1/2016	3294865	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.3720		
Financial	Financial Swap		1/1/2016	3297902	BNP Paribas E,EM	IFERC	Transco Zone 4		$2.4000		
Financial	Financial Swap		1/1/2016	3301240	BNP Paribas E,EM	IFERC	Transco Zone 4		$2.4000		
Financial	Financial Swap		1/1/2016	3306467	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.3720		
Financial	Financial Swap		1/1/2016	3307909	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$2.3720		
Financial	Financial Swap		1/1/2016	3310403	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.4000		
Financial	Financial Swap		1/1/2016	3312109	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.4000		
Financial	Financial Swap		1/1/2016	3317625	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.4000		
Financial	Financial Swap		1/1/2016	3321456	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$2.3720		
Financial	Financial Swap		1/1/2016	3322458	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.3720		
Financial	Financial Swap		1/1/2016	3323024	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.4000		
Financial	Financial Swap		1/1/2016	3324164	Morgan Stanley E	IFERC	Transco Zone 4		$2.4000		
Financial	Financial Swap		1/1/2016	3330749	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$2.3000		
Financial	Financial Swap		1/1/2016	3356603	BKMONTREAL	IFERC	Transco Zone 4		$2.4000		
Financial	Financial Swap		1/1/2016	3364485	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.3720		
Financial	Financial Swap		1/1/2016	3370065	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.3720		
Financial	Financial Swap		1/1/2016	3370773	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.4000		
Financial	Financial Swap		1/1/2016	3371050	Wells Fargo Secur	NYMEX NG L1D	Henry Hub		$2.3720		
		1/1/2016 Total								17,385,600	[redacted]

Attachment B

Financial	Financial Option	Call	2/1/2016	3328129	BKMONTREAL	NYMEX NG L1D	Henry Hub	[redacted]	$2.1890	[redacted]	
Financial	Financial Option	Put	2/1/2016	3328129	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.1890		
Financial	Financial Option	Call	2/1/2016	3331417	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.1890		
Financial	Financial Option	Put	2/1/2016	3331417	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.1890		
Financial	Financial Option	Call	2/1/2016	3339455	Morgan Stanley E	IFERC	Henry Hub		$2.1900		
Financial	Financial Option	Put	2/1/2016	3339455	Morgan Stanley E	IFERC	Henry Hub		$2.1900		
Financial	Financial Option	Call	2/1/2016	3344766	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.2100		
Financial	Financial Option	Put	2/1/2016	3344766	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.2100		
Financial	Financial Option	Call	2/1/2016	3347636	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.1890		
Financial	Financial Option	Put	2/1/2016	3347636	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.1890		
Financial	Financial Option	Call	2/1/2016	3348334	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.1890		
Financial	Financial Option	Put	2/1/2016	3348334	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.1890		
Financial	Financial Option	Call	2/1/2016	3352226	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.1890		
Financial	Financial Option	Put	2/1/2016	3352226	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.1890		
Financial	Financial Option	Call	2/1/2016	3354168	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.1890		
Financial	Financial Option	Put	2/1/2016	3354168	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.1890		
Financial	Financial Swap		2/1/2016	3224926	Morgan Stanley E	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3224928	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3224929	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3225039	Morgan Stanley E	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3225040	JPMorganChase Bank E	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3225041	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3225042	Morgan Stanley E	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3225043	Citigroup Energy E	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3225046	Morgan Stanley E	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3225047	JPMorganChase Bank E	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3225056	JPMorganChase Bank E	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3225060	Macquarie Bank Ltd	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3225068	Citigroup Energy E	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3225069	Citigroup Energy E	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3225071	Morgan Stanley E	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3225088	BKMONTREAL	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3225107	JPMorganChase Bank E	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3225120	Morgan Stanley E	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3225202	BKMONTREAL	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3225203	JPMorganChase Bank E	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3225285	Macquarie Bank Ltd	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3226328	JPMorganChase Bank E	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3226334	JPMorganChase Bank E	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3226373	BKMONTREAL	IFERC	Columbia Gulf		$2.1300		
Financial	Financial Swap		2/1/2016	3226378	BKMONTREAL	IFERC	Transco Zone 4		$2.2100		
Financial	Financial Swap		2/1/2016	3226447	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.2100		
Financial	Financial Swap		2/1/2016	3226554	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.2100		
Financial	Financial Swap		2/1/2016	3226563	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.2100		
Financial	Financial Swap		2/1/2016	3226566	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.2100		
Financial	Financial Swap		2/1/2016	3226569	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.2100		
Financial	Financial Swap		2/1/2016	3226754	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.2100		
Financial	Financial Swap		2/1/2016	3226790	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.2100		

Attachment B

								[redacted]		[redacted]		
Financial	Financial Swap		2/1/2016	3226796	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.1900			
Financial	Financial Swap		2/1/2016	3226801	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.2100			
Financial	Financial Swap		2/1/2016	3226803	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.2100			
Financial	Financial Swap		2/1/2016	3238365	Citigroup Energy E	IFERC	Henry Hub		$2.1900			
Financial	Financial Swap		2/1/2016	3240195	BKMONTREAL	IFERC	Henry Hub		$2.1900			
Financial	Financial Swap		2/1/2016	3243801	BKMONTREAL	IFERC	Henry Hub		$2.1900			
Financial	Financial Swap		2/1/2016	3251815	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.2100			
Financial	Financial Swap		2/1/2016	3257541	Citigroup Energy E	IFERC	Columbia Gulf		$2.1300			
Financial	Financial Swap		2/1/2016	3269357	JPMorganChase Bank E	IFERC	Columbia Gulf		$2.1300			
Financial	Financial Swap		2/1/2016	3286345	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.1890			
Financial	Financial Swap		2/1/2016	3294865	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.1890			
Financial	Financial Swap		2/1/2016	3297902	BNP Paribas E,EM	IFERC	Transco Zone 4		$2.2100			
Financial	Financial Swap		2/1/2016	3301240	BNP Paribas E,EM	IFERC	Transco Zone 4		$2.2100			
Financial	Financial Swap		2/1/2016	3306467	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.1890			
Financial	Financial Swap		2/1/2016	3307909	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$2.1890			
Financial	Financial Swap		2/1/2016	3310403	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.2100			
Financial	Financial Swap		2/1/2016	3312109	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.2100			
Financial	Financial Swap		2/1/2016	3317625	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.2100			
Financial	Financial Swap		2/1/2016	3321456	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$2.1890			
Financial	Financial Swap		2/1/2016	3322458	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.1890			
Financial	Financial Swap		2/1/2016	3323024	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.2100			
Financial	Financial Swap		2/1/2016	3324164	Morgan Stanley E	IFERC	Transco Zone 4		$2.2100			
Financial	Financial Swap		2/1/2016	3330749	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$2.1300			
Financial	Financial Swap		2/1/2016	3356603	BKMONTREAL	IFERC	Transco Zone 4		$2.2100			
Financial	Financial Swap		2/1/2016	3364485	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.1890			
Financial	Financial Swap		2/1/2016	3370065	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.1890			
Financial	Financial Swap		2/1/2016	3370773	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.2100			
		2/1/2016 Total									16,302,300	[redacted]

								[redacted]		[redacted]		
Financial	Financial Swap		2/1/2016	3370773	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.2100			
		2/1/2016 Total									16,302,300	[redacted]

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Financial	Financial Option	Call	3/1/2016	3328129	BKMONTREAL	NYMEX NG L1D	Henry Hub	[redacted]	$1.7110	[redacted]	
Financial	Financial Option	Put	3/1/2016	3328129	BKMONTREAL	NYMEX NG L1D	Henry Hub		$1.7110		
Financial	Financial Option	Call	3/1/2016	3331417	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$1.7110		
Financial	Financial Option	Put	3/1/2016	3331417	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$1.7110		
Financial	Financial Option	Call	3/1/2016	3339455	Morgan Stanley E	IFERC	Henry Hub		$1.7000		
Financial	Financial Option	Put	3/1/2016	3339455	Morgan Stanley E	IFERC	Henry Hub		$1.7000		
Financial	Financial Option	Call	3/1/2016	3344766	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.6900		
Financial	Financial Option	Put	3/1/2016	3344766	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.6900		
Financial	Financial Option	Call	3/1/2016	3347636	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.7110		
Financial	Financial Option	Put	3/1/2016	3347636	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.7110		
Financial	Financial Option	Call	3/1/2016	3348334	BKMONTREAL	NYMEX NG L1D	Henry Hub		$1.7110		
Financial	Financial Option	Put	3/1/2016	3348334	BKMONTREAL	NYMEX NG L1D	Henry Hub		$1.7110		
Financial	Financial Option	Call	3/1/2016	3352226	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$1.7110		
Financial	Financial Option	Put	3/1/2016	3352226	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$1.7110		
Financial	Financial Option	Call	3/1/2016	3354168	Scotia Bank	NYMEX NG L1D	Henry Hub		$1.7110		
Financial	Financial Option	Put	3/1/2016	3354168	Scotia Bank	NYMEX NG L1D	Henry Hub		$1.7110		
Financial	Financial Swap		3/1/2016	3224926	Morgan Stanley E	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3224928	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3224929	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3225039	Morgan Stanley E	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3225040	JPMorganChase Bank E	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3225041	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3225042	Morgan Stanley E	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3225043	Citigroup Energy E	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3225042	Morgan Stanley E	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3225043	Citigroup Energy E	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3225046	Morgan Stanley E	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3225047	JPMorganChase Bank E	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3225056	JPMorganChase Bank E	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3225060	Macquarie Bank Ltd	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3225068	Citigroup Energy E	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3225069	Citigroup Energy E	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3225071	Morgan Stanley E	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3225088	BKMONTREAL	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3225107	JPMorganChase Bank E	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3225120	Morgan Stanley E	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3225202	BKMONTREAL	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3225203	JPMorganChase Bank E	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3225285	Macquarie Bank Ltd	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3226328	JPMorganChase Bank E	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3226334	JPMorganChase Bank E	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3226373	BKMONTREAL	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3226378	BKMONTREAL	IFERC	Transco Zone 4		$1.6900		
Financial	Financial Swap		3/1/2016	3226447	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.6900		
Financial	Financial Swap		3/1/2016	3226554	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.6900		
Financial	Financial Swap		3/1/2016	3226563	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.6900		
Financial	Financial Swap		3/1/2016	3226566	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.6900		
Financial	Financial Swap		3/1/2016	3226569	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.6900		
Financial	Financial Swap		3/1/2016	3226754	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.6900		
Financial	Financial Swap		3/1/2016	3226790	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.6900		

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Financial	Financial Swap		3/1/2016	3226796	MerrilL ynchCom E EM	IFERC	Henry Hub	[redacted]	$1.7000	[redacted]	
Financial	Financial Swap		3/1/2016	3226801	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.6900		
Financial	Financial Swap		3/1/2016	3226803	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.6900		
Financial	Financial Swap		3/1/2016	3238365	Citigroup Energy E	IFERC	Henry Hub		$1.7000		
Financial	Financial Swap		3/1/2016	3240195	BKMONTREAL	IFERC	Henry Hub		$1.7000		
Financial	Financial Swap		3/1/2016	3243801	BKMONTREAL	IFERC	Henry Hub		$1.7000		
Financial	Financial Swap		3/1/2016	3251815	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.6900		
Financial	Financial Swap		3/1/2016	3257541	Citigroup Energy E	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3269357	JPMorganChase Bank E	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3286345	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$1.7110		
Financial	Financial Swap		3/1/2016	3294865	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.7110		
Financial	Financial Swap		3/1/2016	3297902	BNP Paribas E,EM	IFERC	Transco Zone 4		$1.6900		
Financial	Financial Swap		3/1/2016	3301240	BNP Paribas E,EM	IFERC	Transco Zone 4		$1.6900		
Financial	Financial Swap		3/1/2016	3306467	Scotia Bank	NYMEX NG L1D	Henry Hub		$1.7110		
Financial	Financial Swap		3/1/2016	3307909	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$1.7110		
Financial	Financial Swap		3/1/2016	3310403	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.6900		
Financial	Financial Swap		3/1/2016	3312109	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.6900		
Financial	Financial Swap		3/1/2016	3317625	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.6900		
Financial	Financial Swap		3/1/2016	3321456	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$1.7110		
Financial	Financial Swap		3/1/2016	3322458	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$1.7110		
Financial	Financial Swap		3/1/2016	3323024	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.6900		
Financial	Financial Swap		3/1/2016	3324164	Morgan Stanley E	IFERC	Transco Zone 4		$1.6900		
Financial	Financial Swap		3/1/2016	3330749	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$1.6300		
Financial	Financial Swap		3/1/2016	3356603	BKMONTREAL	IFERC	Transco Zone 4		$1.6900		
Financial	Financial Swap		3/1/2016	3370773	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.6900		
		3/1/2016 Total								18,850,300	[redacted]

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Financial	Financial Option	Call	4/1/2016	3227413	Citigroup Energy E	NYMEX NG L1D	Henry Hub	[redacted]	$1.9030	[redacted]	
Financial	Financial Option	Put	4/1/2016	3227413	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Call	4/1/2016	3227513	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Put	4/1/2016	3227513	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Call	4/1/2016	3227514	BKMONTREAL	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Put	4/1/2016	3227514	BKMONTREAL	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Call	4/1/2016	3227515	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.8700		
Financial	Financial Option	Put	4/1/2016	3227515	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.8700		
Financial	Financial Option	Call	4/1/2016	3227516	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.8700		
Financial	Financial Option	Put	4/1/2016	3227516	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.8700		
Financial	Financial Option	Call	4/1/2016	3227517	BKMONTREAL	IFERC	Henry Hub		$1.9000		
Financial	Financial Option	Put	4/1/2016	3227517	BKMONTREAL	IFERC	Henry Hub		$1.9000		
Financial	Financial Option	Call	4/1/2016	3227520	MerrilL ynchCom E EM	IFERC	Henry Hub		$1.9000		
Financial	Financial Option	Put	4/1/2016	3227520	MerrilL ynchCom E EM	IFERC	Henry Hub		$1.9000		
Financial	Financial Option	Call	4/1/2016	3227522	BKMONTREAL	IFERC	Henry Hub		$1.9000		
Financial	Financial Option	Put	4/1/2016	3227522	BKMONTREAL	IFERC	Henry Hub		$1.9000		
Financial	Financial Option	Call	4/1/2016	3238364	BKMONTREAL	IFERC	Henry Hub		$1.9000		
Financial	Financial Option	Put	4/1/2016	3238364	BKMONTREAL	IFERC	Henry Hub		$1.9000		
Financial	Financial Option	Call	4/1/2016	3246476	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Put	4/1/2016	3246476	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Call	4/1/2016	3252181	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Put	4/1/2016	3252181	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Call	4/1/2016	3277474	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Put	4/1/2016	3277474	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Call	4/1/2016	3301242	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Put	4/1/2016	3301242	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Call	4/1/2016	3304155	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Put	4/1/2016	3304155	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Call	4/1/2016	3310402	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Put	4/1/2016	3310402	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Call	4/1/2016	3321632	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Put	4/1/2016	3321632	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Call	4/1/2016	3325562	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Put	4/1/2016	3325562	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Call	4/1/2016	3331417	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Put	4/1/2016	3331417	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Call	4/1/2016	3339455	Morgan Stanley E	IFERC	Henry Hub		$1.9000		
Financial	Financial Option	Put	4/1/2016	3339455	Morgan Stanley E	IFERC	Henry Hub		$1.9000		
Financial	Financial Option	Call	4/1/2016	3344766	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.8700		
Financial	Financial Option	Put	4/1/2016	3344766	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.8700		
Financial	Financial Option	Call	4/1/2016	3370774	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Option	Put	4/1/2016	3370774	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$1.9030		
Financial	Financial Swap		4/1/2016	3225209	Morgan Stanley E	IFERC	Columbia Gulf		$1.8300		
Financial	Financial Swap		4/1/2016	3225282	BKMONTREAL	IFERC	Columbia Gulf		$1.8300		
Financial	Financial Swap		4/1/2016	3225287	JPMorganChase Bank E	IFERC	Columbia Gulf		$1.8300		
Financial	Financial Swap		4/1/2016	3225288	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$1.8300		
Financial	Financial Swap		4/1/2016	3225289	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$1.8300		
Financial	Financial Swap		4/1/2016	3225290	Macquarie Bank Ltd	IFERC	Columbia Gulf		$1.8300		

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Financial	Financial Swap		4/1/2016	3225291	BKMONTREAL	IFERC	Columbia Gulf	[redacted]	$1.8300	[redacted]		
Financial	Financial Swap		4/1/2016	3225858	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3225859	Citigroup Energy E	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3225864	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3225874	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3226122	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3226130	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3226321	Citigroup Energy E	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3226333	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3226348	Citigroup Energy E	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3226375	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3226376	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3226430	BKMONTREAL	IFERC	Columbia Gulf		$1.8300			
Financial	Financial Swap		4/1/2016	3226497	JPMorganChase Bank E	IFERC	Columbia Gulf		$1.8300			
Financial	Financial Swap		4/1/2016	3226553	JPMorganChase Bank E	IFERC	Columbia Gulf		$1.8300			
Financial	Financial Swap		4/1/2016	3226560	JPMorganChase Bank E	IFERC	Columbia Gulf		$1.8300			
Financial	Financial Swap		4/1/2016	3226562	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$1.8300			
Financial	Financial Swap		4/1/2016	3226564	Macquarie Bank Ltd	IFERC	Columbia Gulf		$1.8300			
Financial	Financial Swap		4/1/2016	3226565	Macquarie Bank Ltd	IFERC	Henry Hub		$1.9000			
Financial	Financial Swap		4/1/2016	3226568	BKMONTREAL	IFERC	Henry Hub		$1.9000			
Financial	Financial Swap		4/1/2016	3226746	BKMONTREAL	IFERC	Henry Hub		$1.9000			
Financial	Financial Swap		4/1/2016	3226752	BKMONTREAL	IFERC	Henry Hub		$1.9000			
Financial	Financial Swap		4/1/2016	3226757	JPMorganChase Bank E	IFERC	Henry Hub		$1.9000			
Financial	Financial Swap		4/1/2016	3228844	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3245524	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3267252	Citigroup Energy E	IFERC	Columbia Gulf		$1.8300			
Financial	Financial Swap		4/1/2016	3275165	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$1.8300			
Financial	Financial Swap		4/1/2016	3283780	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$1.8300			
Financial	Financial Swap		4/1/2016	3286346	Macquarie Bank Ltd	IFERC	Columbia Gulf		$1.8300			
Financial	Financial Swap		4/1/2016	3298141	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3317627	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3323025	Citigroup Energy E	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3329156	Morgan Stanley E	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3333884	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3340042	BNP Paribas E,EM	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3340909	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3345068	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3348333	BKMONTREAL	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3349168	BNP Paribas E,EM	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3352499	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3353288	Scotia Bank	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3353713	BKMONTREAL	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3356604	BNP Paribas E,EM	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3356822	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3358458	BKMONTREAL	IFERC	Transco Zone 4		$1.8700			
Financial	Financial Swap		4/1/2016	3365343	BNP Paribas E,EM	IFERC	Columbia Gulf		$1.8300			
Financial	Financial Swap		4/1/2016	3365804	Macquarie Bank Ltd	IFERC	Columbia Gulf		$1.8300			
		4/1/2016 Total									18,904,400	[redacted]

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Financial	Financial Option	Call	5/1/2016	3227413	Citigroup Energy E	NYMEX NG L1D	Henry Hub	[redacted]	$1.9950	[redacted]	
Financial	Financial Option	Put	5/1/2016	3227413	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Call	5/1/2016	3227513	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Put	5/1/2016	3227513	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Call	5/1/2016	3227514	BKMONTREAL	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Put	5/1/2016	3227514	BKMONTREAL	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Call	5/1/2016	3227515	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Option	Put	5/1/2016	3227515	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Option	Call	5/1/2016	3227516	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Option	Put	5/1/2016	3227516	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Option	Call	5/1/2016	3227517	BKMONTREAL	IFERC	Henry Hub		$1.9900		
Financial	Financial Option	Put	5/1/2016	3227517	BKMONTREAL	IFERC	Henry Hub		$1.9900		
Financial	Financial Option	Call	5/1/2016	3227520	MerrilL ynchCom E EM	IFERC	Henry Hub		$1.9900		
Financial	Financial Option	Put	5/1/2016	3227520	MerrilL ynchCom E EM	IFERC	Henry Hub		$1.9900		
Financial	Financial Option	Call	5/1/2016	3227522	BKMONTREAL	IFERC	Henry Hub		$1.9900		
Financial	Financial Option	Put	5/1/2016	3227522	BKMONTREAL	IFERC	Henry Hub		$1.9900		
Financial	Financial Option	Call	5/1/2016	3238364	BKMONTREAL	IFERC	Henry Hub		$1.9900		
Financial	Financial Option	Put	5/1/2016	3238364	BKMONTREAL	IFERC	Henry Hub		$1.9900		
Financial	Financial Option	Call	5/1/2016	3246476	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Put	5/1/2016	3246476	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Call	5/1/2016	3252181	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Put	5/1/2016	3252181	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Call	5/1/2016	3265423	MerrilL ynchCom E EM	IFERC	Henry Hub		$1.9900		
Financial	Financial Option	Put	5/1/2016	3265423	MerrilL ynchCom E EM	IFERC	Henry Hub		$1.9900		
Financial	Financial Option	Call	5/1/2016	3277474	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Put	5/1/2016	3277474	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Call	5/1/2016	3279678	Citigroup Energy E	IFERC	Henry Hub		$1.9900		
Financial	Financial Option	Put	5/1/2016	3279678	Citigroup Energy E	IFERC	Henry Hub		$1.9900		
Financial	Financial Option	Call	5/1/2016	3292220	MerrilL ynchCom E EM	IFERC	Henry Hub		$1.9900		
Financial	Financial Option	Put	5/1/2016	3292220	MerrilL ynchCom E EM	IFERC	Henry Hub		$1.9900		
Financial	Financial Option	Call	5/1/2016	3301242	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Put	5/1/2016	3301242	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Call	5/1/2016	3304155	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Put	5/1/2016	3304155	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Call	5/1/2016	3310402	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Put	5/1/2016	3310402	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Call	5/1/2016	3321632	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Put	5/1/2016	3321632	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Call	5/1/2016	3325562	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Put	5/1/2016	3325562	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Call	5/1/2016	3331417	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Put	5/1/2016	3331417	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Call	5/1/2016	3339455	Morgan Stanley E	IFERC	Henry Hub		$1.9900		
Financial	Financial Option	Put	5/1/2016	3339455	Morgan Stanley E	IFERC	Henry Hub		$1.9900		
Financial	Financial Option	Call	5/1/2016	3344766	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Option	Put	5/1/2016	3344766	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Option	Call	5/1/2016	3370774	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Option	Put	5/1/2016	3370774	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$1.9950		

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Financial	Financial Option	Call	5/1/2016	3390265	Morgan Stanley E	NYMEX NG L1D	Henry Hub	[redacted]	$1.9950	[redacted]	
Financial	Financial Option	Put	5/1/2016	3390265	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$1.9950		
Financial	Financial Swap		5/1/2016	3225209	Morgan Stanley E	IFERC	Columbia Gulf		$1.9100		
Financial	Financial Swap		5/1/2016	3225282	BKMONTREAL	IFERC	Columbia Gulf		$1.9100		
Financial	Financial Swap		5/1/2016	3225287	JPMorganChase Bank E	IFERC	Columbia Gulf		$1.9100		
Financial	Financial Swap		5/1/2016	3225288	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$1.9100		
Financial	Financial Swap		5/1/2016	3225289	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$1.9100		
Financial	Financial Swap		5/1/2016	3225290	Macquarie Bank Ltd	IFERC	Columbia Gulf		$1.9100		
Financial	Financial Swap		5/1/2016	3225291	BKMONTREAL	IFERC	Columbia Gulf		$1.9100		
Financial	Financial Swap		5/1/2016	3225858	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3225859	Citigroup Energy E	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3225864	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3225874	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3226122	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3226130	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3226321	Citigroup Energy E	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3226333	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3226348	Citigroup Energy E	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3226375	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3226376	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3226430	BKMONTREAL	IFERC	Columbia Gulf		$1.9100		
Financial	Financial Swap		5/1/2016	3226497	JPMorganChase Bank E	IFERC	Columbia Gulf		$1.9100		
Financial	Financial Swap		5/1/2016	3226553	JPMorganChase Bank E	IFERC	Columbia Gulf		$1.9100		
Financial	Financial Swap		5/1/2016	3226560	JPMorganChase Bank E	IFERC	Columbia Gulf		$1.9100		
Financial	Financial Swap		5/1/2016	3226562	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$1.9100		
Financial	Financial Swap		5/1/2016	3226564	Macquarie Bank Ltd	IFERC	Columbia Gulf		$1.9100		
Financial	Financial Swap		5/1/2016	3226565	Macquarie Bank Ltd	IFERC	Henry Hub		$1.9900		
Financial	Financial Swap		5/1/2016	3226568	BKMONTREAL	IFERC	Henry Hub		$1.9900		
Financial	Financial Swap		5/1/2016	3226746	BKMONTREAL	IFERC	Henry Hub		$1.9900		
Financial	Financial Swap		5/1/2016	3226752	BKMONTREAL	IFERC	Henry Hub		$1.9900		
Financial	Financial Swap		5/1/2016	3226757	JPMorganChase Bank E	IFERC	Henry Hub		$1.9900		
Financial	Financial Swap		5/1/2016	3228844	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3245524	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3267252	Citigroup Energy E	IFERC	Columbia Gulf		$1.9100		
Financial	Financial Swap		5/1/2016	3275165	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$1.9100		
Financial	Financial Swap		5/1/2016	3283780	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$1.9100		
Financial	Financial Swap		5/1/2016	3286346	Macquarie Bank Ltd	IFERC	Columbia Gulf		$1.9100		
Financial	Financial Swap		5/1/2016	3298141	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3317627	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3323025	Citigroup Energy E	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3329156	Morgan Stanley E	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3333884	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3340042	BNP Paribas E,EM	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3340909	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3345068	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3348333	BKMONTREAL	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3349168	BNP Paribas E,EM	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3352499	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.9500		
Financial	Financial Swap		5/1/2016	3353288	Scotia Bank	IFERC	Transco Zone 4		$1.9500		

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Financial	Financial Swap		5/1/2016	3353713	BKMONTREAL	IFERC	Transco Zone 4	[redacted]	$1.9500	[redacted]		
Financial	Financial Swap		5/1/2016	3356604	BNP Paribas E,EM	IFERC	Transco Zone 4		$1.9500			
Financial	Financial Swap		5/1/2016	3356822	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.9500			
Financial	Financial Swap		5/1/2016	3358458	BKMONTREAL	IFERC	Transco Zone 4		$1.9500			
Financial	Financial Swap		5/1/2016	3359032	Scotia Bank	IFERC	Henry Hub		$1.9900			
Financial	Financial Swap		5/1/2016	3360082	Morgan Stanley E	IFERC	Henry Hub		$1.9900			
Financial	Financial Swap		5/1/2016	3360554	BKMONTREAL	IFERC	Henry Hub		$1.9900			
Financial	Financial Swap		5/1/2016	3363536	Morgan Stanley E	IFERC	Henry Hub		$1.9900			
Financial	Financial Swap		5/1/2016	3364483	Scotia Bank	IFERC	Henry Hub		$1.9900			
Financial	Financial Swap		5/1/2016	3364688	BKMONTREAL	IFERC	Henry Hub		$1.9900			
Financial	Financial Swap		5/1/2016	3365343	BNP Paribas E,EM	IFERC	Columbia Gulf		$1.9100			
Financial	Financial Swap		5/1/2016	3365804	Macquarie Bank Ltd	IFERC	Columbia Gulf		$1.9100			
Financial	Financial Swap		5/1/2016	3368346	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$1.9950			
		5/1/2016 Total									24,722,000	[redacted]

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Financial	Financial Option	Call	6/1/2016	3227413	Citigroup Energy E	NYMEX NG L1D	Henry Hub	[redacted]	$1.9630	[redacted]	
Financial	Financial Option	Put	6/1/2016	3227413	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Call	6/1/2016	3227513	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Put	6/1/2016	3227513	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Call	6/1/2016	3227514	BKMONTREAL	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Put	6/1/2016	3227514	BKMONTREAL	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Call	6/1/2016	3227515	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Option	Put	6/1/2016	3227515	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Option	Call	6/1/2016	3227516	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Option	Put	6/1/2016	3227516	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Option	Call	6/1/2016	3227517	BKMONTREAL	IFERC	Henry Hub		$1.9600		
Financial	Financial Option	Put	6/1/2016	3227517	BKMONTREAL	IFERC	Henry Hub		$1.9600		
Financial	Financial Option	Call	6/1/2016	3227520	MerrilL ynchCom E EM	IFERC	Henry Hub		$1.9600		
Financial	Financial Option	Put	6/1/2016	3227520	MerrilL ynchCom E EM	IFERC	Henry Hub		$1.9600		
Financial	Financial Option	Call	6/1/2016	3227522	BKMONTREAL	IFERC	Henry Hub		$1.9600		
Financial	Financial Option	Put	6/1/2016	3227522	BKMONTREAL	IFERC	Henry Hub		$1.9600		
Financial	Financial Option	Call	6/1/2016	3238364	BKMONTREAL	IFERC	Henry Hub		$1.9600		
Financial	Financial Option	Put	6/1/2016	3238364	BKMONTREAL	IFERC	Henry Hub		$1.9600		
Financial	Financial Option	Call	6/1/2016	3246476	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Put	6/1/2016	3246476	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Call	6/1/2016	3252181	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Put	6/1/2016	3252181	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Call	6/1/2016	3265423	MerrilL ynchCom E EM	IFERC	Henry Hub		$1.9600		
Financial	Financial Option	Put	6/1/2016	3265423	MerrilL ynchCom E EM	IFERC	Henry Hub		$1.9600		
Financial	Financial Option	Call	6/1/2016	3277474	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Put	6/1/2016	3277474	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Call	6/1/2016	3279678	Citigroup Energy E	IFERC	Henry Hub		$1.9600		
Financial	Financial Option	Put	6/1/2016	3279678	Citigroup Energy E	IFERC	Henry Hub		$1.9600		
Financial	Financial Option	Call	6/1/2016	3292220	MerrilL ynchCom E EM	IFERC	Henry Hub		$1.9600		
Financial	Financial Option	Put	6/1/2016	3292220	MerrilL ynchCom E EM	IFERC	Henry Hub		$1.9600		
Financial	Financial Option	Call	6/1/2016	3301242	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Put	6/1/2016	3301242	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Call	6/1/2016	3304155	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Put	6/1/2016	3304155	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Call	6/1/2016	3310402	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Put	6/1/2016	3310402	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Call	6/1/2016	3321632	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Put	6/1/2016	3321632	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Call	6/1/2016	3325562	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Put	6/1/2016	3325562	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Call	6/1/2016	3331417	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Put	6/1/2016	3331417	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Call	6/1/2016	3339455	Morgan Stanley E	IFERC	Henry Hub		$1.9600		
Financial	Financial Option	Put	6/1/2016	3339455	Morgan Stanley E	IFERC	Henry Hub		$1.9600		
Financial	Financial Option	Call	6/1/2016	3344766	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Option	Put	6/1/2016	3344766	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Option	Call	6/1/2016	3370774	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Put	6/1/2016	3370774	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$1.9630		

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Financial	Financial Option	Call	6/1/2016	3389346	Scotia Bank	NYMEX NG L1D	Henry Hub	[redacted]	$1.9630	[redacted]	
Financial	Financial Option	Put	6/1/2016	3389346	Scotia Bank	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Call	6/1/2016	3390265	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Option	Put	6/1/2016	3390265	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Swap		6/1/2016	3225209	Morgan Stanley E	IFERC	Columbia Gulf		$1.8800		
Financial	Financial Swap		6/1/2016	3225282	BKMONTREAL	IFERC	Columbia Gulf		$1.8800		
Financial	Financial Swap		6/1/2016	3225287	JPMorganChase Bank E	IFERC	Columbia Gulf		$1.8800		
Financial	Financial Swap		6/1/2016	3225288	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$1.8800		
Financial	Financial Swap		6/1/2016	3225289	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$1.8800		
Financial	Financial Swap		6/1/2016	3225290	Macquarie Bank Ltd	IFERC	Columbia Gulf		$1.8800		
Financial	Financial Swap		6/1/2016	3225291	BKMONTREAL	IFERC	Columbia Gulf		$1.8800		
Financial	Financial Swap		6/1/2016	3225858	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3225859	Citigroup Energy E	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3225864	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3225874	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3226122	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3226130	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3226321	Citigroup Energy E	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3226333	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3226348	Citigroup Energy E	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3226375	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3226376	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3226430	BKMONTREAL	IFERC	Columbia Gulf		$1.8800		
Financial	Financial Swap		6/1/2016	3226497	JPMorganChase Bank E	IFERC	Columbia Gulf		$1.8800		
Financial	Financial Swap		6/1/2016	3226553	JPMorganChase Bank E	IFERC	Columbia Gulf		$1.8800		
Financial	Financial Swap		6/1/2016	3226560	JPMorganChase Bank E	IFERC	Columbia Gulf		$1.8800		
Financial	Financial Swap		6/1/2016	3226562	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$1.8800		
Financial	Financial Swap		6/1/2016	3226564	Macquarie Bank Ltd	IFERC	Columbia Gulf		$1.8800		
Financial	Financial Swap		6/1/2016	3226565	Macquarie Bank Ltd	IFERC	Henry Hub		$1.9600		
Financial	Financial Swap		6/1/2016	3226568	BKMONTREAL	IFERC	Henry Hub		$1.9600		
Financial	Financial Swap		6/1/2016	3226746	BKMONTREAL	IFERC	Henry Hub		$1.9600		
Financial	Financial Swap		6/1/2016	3226752	BKMONTREAL	IFERC	Henry Hub		$1.9600		
Financial	Financial Swap		6/1/2016	3226757	JPMorganChase Bank E	IFERC	Henry Hub		$1.9600		
Financial	Financial Swap		6/1/2016	3228844	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3245524	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3267252	Citigroup Energy E	IFERC	Columbia Gulf		$1.8800		
Financial	Financial Swap		6/1/2016	3275165	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$1.8800		
Financial	Financial Swap		6/1/2016	3283780	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$1.8800		
Financial	Financial Swap		6/1/2016	3286346	Macquarie Bank Ltd	IFERC	Columbia Gulf		$1.8800		
Financial	Financial Swap		6/1/2016	3298141	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3317627	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3323025	Citigroup Energy E	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3329156	Morgan Stanley E	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3333884	JPMorganChase Bank E	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3340042	BNP Paribas E,EM	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3340909	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3345068	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3348333	BKMONTREAL	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3349168	BNP Paribas E,EM	IFERC	Transco Zone 4		$1.9200		

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Financial	Financial Swap		6/1/2016	3352499	Macquarie Bank Ltd	IFERC	Transco Zone 4	[redacted]	$1.9200	[redacted]	
Financial	Financial Swap		6/1/2016	3353288	Scotia Bank	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3353713	BKMONTREAL	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3356604	BNP Paribas E,EM	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3356822	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3358458	BKMONTREAL	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3359032	Scotia Bank	IFERC	Henry Hub		$1.9600		
Financial	Financial Swap		6/1/2016	3360082	Morgan Stanley E	IFERC	Henry Hub		$1.9600		
Financial	Financial Swap		6/1/2016	3360554	BKMONTREAL	IFERC	Henry Hub		$1.9600		
Financial	Financial Swap		6/1/2016	3363536	Morgan Stanley E	IFERC	Henry Hub		$1.9600		
Financial	Financial Swap		6/1/2016	3364483	Scotia Bank	IFERC	Henry Hub		$1.9600		
Financial	Financial Swap		6/1/2016	3364688	BKMONTREAL	IFERC	Henry Hub		$1.9600		
Financial	Financial Swap		6/1/2016	3365343	BNP Paribas E,EM	IFERC	Columbia Gulf		$1.8800		
Financial	Financial Swap		6/1/2016	3365804	Macquarie Bank Ltd	IFERC	Columbia Gulf		$1.8800		
Financial	Financial Swap		6/1/2016	3368346	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Swap		6/1/2016	3368666	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3369208	BKMONTREAL	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3370066	Macquarie Bank Ltd	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3370588	BKMONTREAL	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3374592	BKMONTREAL	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3376795	BNP Paribas E,EM	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3377979	BNP Paribas E,EM	IFERC	Transco Zone 4		$1.9200		
Financial	Financial Swap		6/1/2016	3382168	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$1.9630		
Financial	Financial Swap		6/1/2016	3383267	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$1.9630		
		6/1/2016 Total								24,413,900	[redacted]

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Financial	Financial Option	Call	7/1/2016	3227413	Citigroup Energy E	NYMEX NG L1D	Henry Hub	[redacted]	$2.9170	[redacted]	
Financial	Financial Option	Put	7/1/2016	3227413	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Call	7/1/2016	3227513	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Put	7/1/2016	3227513	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Call	7/1/2016	3227514	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Put	7/1/2016	3227514	BKMONTREAL	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Call	7/1/2016	3227515	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Option	Put	7/1/2016	3227515	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Option	Call	7/1/2016	3227516	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Option	Put	7/1/2016	3227516	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Option	Call	7/1/2016	3227517	BKMONTREAL	IFERC	Henry Hub		$2.9200		
Financial	Financial Option	Put	7/1/2016	3227517	BKMONTREAL	IFERC	Henry Hub		$2.9200		
Financial	Financial Option	Call	7/1/2016	3227520	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.9200		
Financial	Financial Option	Put	7/1/2016	3227520	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.9200		
Financial	Financial Option	Call	7/1/2016	3227522	BKMONTREAL	IFERC	Henry Hub		$2.9200		
Financial	Financial Option	Put	7/1/2016	3227522	BKMONTREAL	IFERC	Henry Hub		$2.9200		
Financial	Financial Option	Call	7/1/2016	3238364	BKMONTREAL	IFERC	Henry Hub		$2.9200		
Financial	Financial Option	Put	7/1/2016	3238364	BKMONTREAL	IFERC	Henry Hub		$2.9200		
Financial	Financial Option	Call	7/1/2016	3246476	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Put	7/1/2016	3246476	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Call	7/1/2016	3252181	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Put	7/1/2016	3252181	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Call	7/1/2016	3265423	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.9200		
Financial	Financial Option	Put	7/1/2016	3265423	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.9200		
Financial	Financial Option	Call	7/1/2016	3277474	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Put	7/1/2016	3277474	MerrilL ynchCom E EM	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Call	7/1/2016	3279678	Citigroup Energy E	IFERC	Henry Hub		$2.9200		
Financial	Financial Option	Put	7/1/2016	3279678	Citigroup Energy E	IFERC	Henry Hub		$2.9200		
Financial	Financial Option	Call	7/1/2016	3292220	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.9200		
Financial	Financial Option	Put	7/1/2016	3292220	MerrilL ynchCom E EM	IFERC	Henry Hub		$2.9200		
Financial	Financial Option	Call	7/1/2016	3301242	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Put	7/1/2016	3301242	Citigroup Energy E	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Call	7/1/2016	3304155	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Put	7/1/2016	3304155	JPMorganChase Bank E	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Call	7/1/2016	3310402	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Put	7/1/2016	3310402	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Call	7/1/2016	3321632	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Put	7/1/2016	3321632	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Call	7/1/2016	3325562	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Put	7/1/2016	3325562	Macquarie Bank Ltd	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Call	7/1/2016	3331417	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Put	7/1/2016	3331417	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Call	7/1/2016	3339455	Morgan Stanley E	IFERC	Henry Hub		$2.9200		
Financial	Financial Option	Put	7/1/2016	3339455	Morgan Stanley E	IFERC	Henry Hub		$2.9200		
Financial	Financial Option	Call	7/1/2016	3344766	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Option	Put	7/1/2016	3344766	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Option	Call	7/1/2016	3370774	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Put	7/1/2016	3370774	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$2.9170		

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Financial	Financial Option	Call	7/1/2016	3389346	Scotia Bank	NYMEX NG L1D	Henry Hub	[redacted]	$2.9170	[redacted]	
Financial	Financial Option	Put	7/1/2016	3389346	Scotia Bank	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Call	7/1/2016	3390265	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Option	Put	7/1/2016	3390265	Morgan Stanley E	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Swap		7/1/2016	3225209	Morgan Stanley E	IFERC	Columbia Gulf		$2.8400		
Financial	Financial Swap		7/1/2016	3225282	BKMONTREAL	IFERC	Columbia Gulf		$2.8400		
Financial	Financial Swap		7/1/2016	3225287	JPMorganChase Bank E	IFERC	Columbia Gulf		$2.8400		
Financial	Financial Swap		7/1/2016	3225288	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$2.8400		
Financial	Financial Swap		7/1/2016	3225289	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$2.8400		
Financial	Financial Swap		7/1/2016	3225290	Macquarie Bank Ltd	IFERC	Columbia Gulf		$2.8400		
Financial	Financial Swap		7/1/2016	3225291	BKMONTREAL	IFERC	Columbia Gulf		$2.8400		
Financial	Financial Swap		7/1/2016	3225858	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3225859	Citigroup Energy E	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3225864	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3225874	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3226122	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3226130	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3226321	Citigroup Energy E	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3226333	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3226348	Citigroup Energy E	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3226375	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3226376	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3226430	BKMONTREAL	IFERC	Columbia Gulf		$2.8400		
Financial	Financial Swap		7/1/2016	3226497	JPMorganChase Bank E	IFERC	Columbia Gulf		$2.8400		
Financial	Financial Swap		7/1/2016	3226553	JPMorganChase Bank E	IFERC	Columbia Gulf		$2.8400		
Financial	Financial Swap		7/1/2016	3226560	JPMorganChase Bank E	IFERC	Columbia Gulf		$2.8400		
Financial	Financial Swap		7/1/2016	3226562	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$2.8400		
Financial	Financial Swap		7/1/2016	3226564	Macquarie Bank Ltd	IFERC	Columbia Gulf		$2.8400		
Financial	Financial Swap		7/1/2016	3226565	Macquarie Bank Ltd	IFERC	Henry Hub		$2.9200		
Financial	Financial Swap		7/1/2016	3226568	BKMONTREAL	IFERC	Henry Hub		$2.9200		
Financial	Financial Swap		7/1/2016	3226746	BKMONTREAL	IFERC	Henry Hub		$2.9200		
Financial	Financial Swap		7/1/2016	3226752	BKMONTREAL	IFERC	Henry Hub		$2.9200		
Financial	Financial Swap		7/1/2016	3226757	JPMorganChase Bank E	IFERC	Henry Hub		$2.9200		
Financial	Financial Swap		7/1/2016	3228844	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3245524	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3267252	Citigroup Energy E	IFERC	Columbia Gulf		$2.8400		
Financial	Financial Swap		7/1/2016	3275165	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$2.8400		
Financial	Financial Swap		7/1/2016	3283780	MerrilL ynchCom E EM	IFERC	Columbia Gulf		$2.8400		
Financial	Financial Swap		7/1/2016	3286346	Macquarie Bank Ltd	IFERC	Columbia Gulf		$2.8400		
Financial	Financial Swap		7/1/2016	3298141	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3317627	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3323025	Citigroup Energy E	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3329156	Morgan Stanley E	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3333884	JPMorganChase Bank E	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3340042	BNP Paribas E,EM	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3340909	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3345068	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3348333	BKMONTREAL	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3349168	BNP Paribas E,EM	IFERC	Transco Zone 4		$2.9000		

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Financial	Financial Swap		7/1/2016	3352499	Macquarie Bank Ltd	IFERC	Transco Zone 4	[redacted]	$2.9000	[redacted]	
Financial	Financial Swap		7/1/2016	3353288	Scotia Bank	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3353713	BKMONTREAL	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3356604	BNP Paribas E,EM	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3356822	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3358458	BKMONTREAL	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3359032	Scotia Bank	IFERC	Henry Hub		$2.9200		
Financial	Financial Swap		7/1/2016	3360082	Morgan Stanley E	IFERC	Henry Hub		$2.9200		
Financial	Financial Swap		7/1/2016	3360554	BKMONTREAL	IFERC	Henry Hub		$2.9200		
Financial	Financial Swap		7/1/2016	3363536	Morgan Stanley E	IFERC	Henry Hub		$2.9200		
Financial	Financial Swap		7/1/2016	3364483	Scotia Bank	IFERC	Henry Hub		$2.9200		
Financial	Financial Swap		7/1/2016	3364688	BKMONTREAL	IFERC	Henry Hub		$2.9200		
Financial	Financial Swap		7/1/2016	3365343	BNP Paribas E,EM	IFERC	Columbia Gulf		$2.8400		
Financial	Financial Swap		7/1/2016	3365804	Macquarie Bank Ltd	IFERC	Columbia Gulf		$2.8400		
Financial	Financial Swap		7/1/2016	3368346	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Swap		7/1/2016	3368666	MerrilL ynchCom E EM	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3369208	BKMONTREAL	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3370066	Macquarie Bank Ltd	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3370588	BKMONTREAL	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3374592	BKMONTREAL	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3376795	BNP Paribas E,EM	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3377979	BNP Paribas E,EM	IFERC	Transco Zone 4		$2.9000		
Financial	Financial Swap		7/1/2016	3382168	BNP Paribas E,EM	NYMEX NG L1D	Henry Hub		$2.9170		
Financial	Financial Swap		7/1/2016	3383267	NextEra EnergyE EM G	NYMEX NG L1D	Henry Hub		$2.9170		
		7/1/2016 Total						[redacted]		26,459,200	[redacted]

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DEF Gas Storage Hedging Status
REDACTED

As of July 31, 2016

Physical/ Financial	Instrument	Month	Trade Number	Counterparty	Market	Location	Volume	Fixed Price ($/MMBtu)	IFERC Settlement ($/MMBtu)	Savings/Cost on Hedge	Actual/Projected Injection	% Hedged
Financial	Financial Swap	6/1/2016	3383865	Morgan Stanley E	IFERC	FGT Zone 3	[redacted]	[redacted]	$1.9600	[redacted]		
	6/1/2016 Total										250,000	[redacted]

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DEF Coal Transportation Hedging Status - Barge
REDACTED

As of July 31, 2016

Physical/ Financial	Instrument	Month	Trade Number	Counterparty	Market	Location	Volume (Gallons)	Fixed Price ($/Gallons)	Market Settlement ($/Gallons)	Estimated Savings/(Cost) on Hedge	Estimated Exposure (Gallons)	Total % Estimated Hedged Exposure
Financial	Financial Swap	1/1/2016	3370646	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$0.9561			
Financial	Financial Swap	1/1/2016	3370647	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$0.9561			
Financial	Financial Swap	1/1/2016	3370674	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$0.9561			
Financial	Financial Swap	1/1/2016	3370776	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$0.9561			
Financial	Financial Swap	1/1/2016	3371053	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$0.9561			
		1/1/2016 Total									768,155	
Financial	Financial Swap	2/1/2016	3370646	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$0.9958			
Financial	Financial Swap	2/1/2016	3370647	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$0.9958			
Financial	Financial Swap	2/1/2016	3370674	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$0.9958			
Financial	Financial Swap	2/1/2016	3370776	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$0.9958			
Financial	Financial Swap	2/1/2016	3371053	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$0.9958			
		2/1/2016 Total									758,592	
Financial	Financial Swap	3/1/2016	3370646	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1291			
Financial	Financial Swap	3/1/2016	3370647	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1291			
Financial	Financial Swap	3/1/2016	3370674	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1291			
Financial	Financial Swap	3/1/2016	3370776	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1291			
Financial	Financial Swap	3/1/2016	3371053	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1291			
		3/1/2016 Total									752,321	
Financial	Financial Swap	4/1/2016	3374757	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.2006			
Financial	Financial Swap	4/1/2016	3380940	MerrilL ynchCom E EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.2006			
Financial	Financial Swap	4/1/2016	3384449	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.2006			
Financial	Financial Swap	4/1/2016	3386308	MerrilL ynchCom E EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.2006			
Financial	Financial Swap	4/1/2016	3386741	MerrilL ynchCom E EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.2006			
Financial	Financial Swap	4/1/2016	3387221	MerrilL ynchCom E EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.2006			
Financial	Financial Swap	4/1/2016	3387222	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.2006			
Financial	Financial Swap	4/1/2016	3388336	MerrilL ynchCom E EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.2006			
		4/1/2016 Total									854,056	
Financial	Financial Swap	5/1/2016	3374757	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.3754			
Financial	Financial Swap	5/1/2016	3380940	MerrilL ynchCom E EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.3754			
Financial	Financial Swap	5/1/2016	3384449	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.3754			
Financial	Financial Swap	5/1/2016	3386308	MerrilL ynchCom E EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.3754			
Financial	Financial Swap	5/1/2016	3386741	MerrilL ynchCom E EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.3754			
Financial	Financial Swap	5/1/2016	3387221	MerrilL ynchCom E EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.3754			
Financial	Financial Swap	5/1/2016	3387222	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.3754			
Financial	Financial Swap	5/1/2016	3388336	MerrilL ynchCom E EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.3754			
		5/1/2016 Total									779,496	
Financial	Financial Swap	6/1/2016	3374757	JPMorganChase Bank E	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.4585			
Financial	Financial Swap	6/1/2016	3380940	MerrilL ynchCom E EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.4585			
Financial	Financial Swap	6/1/2016	3384449	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.4585			

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Financial	Financial Swap	6/1/2016	3386308	MerrilL ynchCom E EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline	[redacted]	$1.4585	[redacted]		[redacted]
Financial	Financial Swap	6/1/2016	3386741	MerrilL ynchCom E EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline		$1.4585			
Financial	Financial Swap	6/1/2016	3387221	MerrilL ynchCom E EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline		$1.4585			
Financial	Financial Swap	6/1/2016	3387222	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline		$1.4585			
		6/1/2016 Total								461,517	
Financial	Financial Swap	7/1/2016	3375682	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline		$1.3347			
Financial	Financial Swap	7/1/2016	3380940	MerrilL ynchCom E EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline		$1.3347			
Financial	Financial Swap	7/1/2016	3384449	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline		$1.3347			
Financial	Financial Swap	7/1/2016	3386308	MerrilL ynchCom E EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline		$1.3347			
Financial	Financial Swap	7/1/2016	3386741	MerrilL ynchCom E EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline		$1.3347			
Financial	Financial Swap	7/1/2016	3387221	MerrilL ynchCom E EM	Gulfcoast Pipe ULSD	Gulf Coast Pipeline		$1.3347			
Financial	Financial Swap	7/1/2016	3387222	BKMONTREAL	Gulfcoast Pipe ULSD	Gulf Coast Pipeline		$1.3347			
		7/1/2016 Total								354,594	

Duke Energy Florida
Docket No. 150001-EI
Witness: JONES
Exhibit No. _____ (MJJ-1T)

GPIF REWARD/PENALTY SCHEDULES

Description	Sheet
Index	1
Reward/Penalty Table (Actual)	2
Calculation of Maximum Incentive Dollars (Actual)	3
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PARTY: DUKE ENERGY FLORIDA, LLC – (DIRECT)
DESCRIPTION: Matthew J. Jones MJJ-1T

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GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ACTUAL

Duke Energy Florida
Janauary 2015 - December 2015

	Generating Performance Incentive Points (GPIF)	Fuel Savings/Loss ($)	Generating Performance Incentive Factor ($)
	10	$ 68,790,939	$ 20,710,935
	9	$ 61,911,845	$ 18,639,841
	8	$ 55,032,751	$ 16,568,748
	7	$ 48,153,657	$ 14,497,654
	6	$ 41,274,563	$ 12,426,561
	5	$ 34,395,469	$ 10,355,467
	4	$ 27,516,375	$ 8,284,374
	3	$ 20,637,282	$ 6,213,280
	2	$ 13,758,188	$ 4,142,187
****	1.089	$ 7,491,333	$ 2,255,421
	1	$ 6,879,094	$ 2,071,093
	0	$ -	$ -
	-1	$ (7,477,634)	$ (2,071,093)
	-2	$ (14,955,268)	$ (4,142,187)
	-3	$ (22,432,902)	$ (6,213,280)
	-4	$ (29,910,535)	$ (8,284,374)
	-5	$ (37,388,169)	$ (10,355,467)
	-6	$ (44,865,803)	$ (12,426,561)
	-7	$ (52,343,437)	$ (14,497,654)
	-8	$ (59,821,071)	$ (16,568,748)
	-9	$ (67,298,705)	$ (18,639,841)
	-10	$ (74,776,339)	$ (20,710,935)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

Duke Energy Florida
Janauary 2015 - December 2015

1	Beginning of period balance of common equity	$ 5,451,505,259	
	END OF MONTH BALANCE OF COMMON EQUITY:		
2	Month of JANUARY 2015	$ 5,282,300,994	
3	Month of FEBRUARY 2015	$ 5,300,608,729	
4	Month of MARCH 2015	$ 4,985,043,387	
5	Month of APRIL 2015	$ 5,026,468,678	
6	Month of MAY 2015	$ 5,079,592,889	
7	Month of JUNE 2015	$ 5,149,631,456	
8	Month of JULY 2015	$ 5,222,507,185	
9	Month of AUGUST 2015	$ 4,926,982,806	
10	Month of SEPTEMBER 2015	$ 5,015,990,982	
11	Month of OCTOBER 2015	$ 5,062,307,351	
12	Month of NOVEMBER 2015	$ 5,094,701,751	
13	Month of DECEMBER 2015	$ 5,121,368,695	
14	Average common equity for the period	$ 5,132,231,551	
15	25 Basis Points	0.0025	
16	Revenue Expansion Factor	61.3808%	
17	Maximum allowed incentive dollars	$ 20,903,245	
18	Jurisdictional Sales *	38,553,182	MWH
19	Total Sales *	38,911,308	MWH
20	Jurisdictional Separation Factor	99.0800%	
21	Maximum allowed jurisdictional incentive dollars	$ 20,710,935	
22	Incentive Cap (50% of Projected Fuel Savings at 10 GPIF Point Level) From Sheet No. 6.101.1	$ 24,076,829	
23	Maximum Allowed GPIF Reward (Lesser of Line 21 and Line 22)	$ 20,710,935	

* Net sales (Sales - Interruptible)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF SYSTEM ACTUAL GPIF POINTS

Duke Energy Florida
Janauary 2015 - December 2015

Plant/Unit	Performance Indicator EAF or ANOHR	Weighting Factor %	Unit Points	Weighted Unit Points
Bartow CC	EAF	3.62	5.353	0.194
	ANOHR	23.18	0.000	0.000
Crystal River 4	EAF	4.62	9.067	0.419
	ANOHR	11.58	0.000	0.000
Crystal River 5	EAF	3.34	10.000	0.334
	ANOHR	10.49	2.337	0.245
Hines 1	EAF	0.58	8.355	0.048
	ANOHR	11.37	-1.292	-0.147
Hines 2	EAF	0.63	-10.000	-0.063
	ANOHR	7.99	0.000	0.000
Hines 3	EAF	1.07	10.000	0.107
	ANOHR	13.42	0.000	0.000
Hines 4	EAF	0.57	5.076	0.029
	ANOHR	7.54	-1.021	-0.077
GPIF System		100.00		1.089

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GENERATION PERFORMANCE INCENTIVE FACTOR
GPIF UNIT PERFORMANCE SUMMARY

Duke Energy Florida
Janauary 2015 - December 2015

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	3.62	87.48	89.95	82.43	$2,487	($3,099)	88.81	$1,331
Crystal River 4	4.62	91.86	95.65	84.32	$3,181	($5,861)	95.29	$2,884
Crystal River 5	3.34	89.21	91.57	84.43	$2,301	($4,230)	92.08	$2,301
Hines 1	0.58	86.26	87.32	84.08	$397	($1,007)	87.14	$332
Hines 2	0.63	89.24	89.79	88.08	$431	($406)	48.97	($406)
Hines 3	1.07	92.28	93.21	90.36	$734	($987)	93.44	$734
Hines 4	0.57	86.67	87.08	85.81	$391	($318)	86.88	$198
GPIF System	14.42				$9,922.0	($15,907.4)		$7,374.7

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	23.18	7,451	75.9	7,060	7,842	$15,949	($15,949)	7,410	$0
Crystal River 4	11.58	10,354	83.3	9,885	10,823	$7,968	($7,968)	10,336	$0
Crystal River 5	10.49	10,157	83.5	9,715	10,600	$7,214	($7,214)	9,996	$1,686
Hines 1	11.37	7,266	96.1	6,823	7,708	$7,824	($7,824)	7,388	($1,011)
Hines 2	7.99	7,225	87.0	6,870	7,579	$5,495	($5,495)	7,200	$0
Hines 3	13.42	7,151	95.1	6,680	7,623	$9,234	($9,234)	7,168	$0
Hines 4	7.54	6,964	92.1	6,695	7,233	$5,185	($5,185)	7,059	($529)
GPIF System	85.58					$58,868.9	($58,868.9)		$145.6

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GENERATION PERFORMANCE INCENTIVE FACTOR
ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida
Janauary 2015 - December 2015

Plant/Unit	ACTUAL EAF %	ADJUSTMENTS (1) TO EAF %	ADJUSTED ACTUAL EAF %
Bartow CC	87.89	0.91	88.81
Crystal River 4	95.29	0.00	95.29
Crystal River 5	91.81	0.27	92.08
Hines 1	83.55	3.59	87.14
Hines 2	54.16	-5.19	48.97
Hines 3	92.86	0.58	93.44
Hines 4	88.60	-1.72	86.88

Plant/Unit	ACTUAL ANOHR BTU/KWH	ADJUSTMENTS (2) TO ANOHR BTU/KWH	ADJUSTED ACTUAL ANOHR BTU/KWH
Bartow CC	7,391.3	19.1	7,410.3
Crystal River 4	10,468.1	-131.7	10,336.5
Crystal River 5	10,272.5	-276.1	9,996.5
Hines 1	7,399.4	-11.4	7,388.0
Hines 2	7,199.9	0.0	7,199.9
Hines 3	7,161.9	6.1	7,167.9
Hines 4	7,049.8	9.3	7,059.1

(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
Janauary 2015 - December 2015

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.	719.41	0.00	528.02	1,327.35	1.49	555.63	939.90
2	Target POH	Hrs.	636.00	0.00	504.00	1,008.00	840.00	504.00	1,092.00
3	Adj. Factor (PH-POHT/PH-POHA)		1.01	1.00	1.00	1.04	0.90	1.01	0.98
4	Actual EUOH	Hrs.	341.01	412.29	189.41	113.32	4,014.09	70.01	58.74
5	Adj. EUOH (3*4)	Hrs.	344.55	412.29	189.96	118.19	3,629.79	70.45	57.60
6	Actual EAF	%	87.89	95.29	91.81	83.55	54.16	92.86	88.60
7	Adjusted EAF (using 2 & 5)	%	88.81	95.29	92.08	87.14	48.97	93.44	86.88
8	Difference (7-6)	%	0.91	0.00	0.27	3.59	-5.19	0.58	-1.72
9	Total adj. to EAF	%	0.91	0.00	0.27	3.59	-5.19	0.58	-1.72

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GENERATION PERFORMANCE INCENTIVE FACTOR
ADJUSTMENTS TO ANOHR ACTUAL

Duke Energy Florida
Janauary 2015 - December 2015

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	%	75.9	83.3	83.5	96.1	87.0	95.1	92.1
2	Target ANOHR	Btu/kwh	7450.9	10353.7	10157.3	7265.5	7224.6	7151.3	6964.3
3	Actual NOF	%	77.6	67.7	71.1	95.4	93.6	95.6	97.0
4	Calc. ANOHR (using 3)	Btu/kwh	7,431.9	10,485.3	10,433.3	7,277.0	7,167.1	7,145.2	6,955.0
5	Total adj. to ANOHR (2-4)	Btu/kwh	19.1	-131.7	-276.1	-11.4	0.0	6.1	9.3

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Janauary 2015 - December 2015

Unit: Bartow CC

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$2,487,200	89.95	10	$15,948,746	7,059.8	
	9	$2,238,480	89.71	9	$14,353,871	7,091.4	
	8	$1,989,760	89.46	8	$12,758,997	7,123.0	
	7	$1,741,040	89.21	7	$11,164,122	7,154.6	
	6	$1,492,320	88.97	6	$9,569,248	7,186.3	
****	5.353	$1,331,398	88.81	5	$7,974,373	7,217.9	
	5	$1,243,600	88.72	4	$6,379,498	7,249.5	
	4	$994,880	88.47	3	$4,784,624	7,281.1	
	3	$746,160	88.23	2	$3,189,749	7,312.7	
	2	$497,440	87.98	1	$1,594,875	7,344.3	
	1	$248,720	87.73	0	$0	7,375.9	
		$0	87.48	0.000	$0	7,410.3	****
	0	$0	87.48	0	$0	7,450.9	
		$0	87.48	0	$0	7,525.9	
	-1	($309,870)	86.98	-1	($1,594,875)	7,557.6	
	-2	($619,740)	86.47	-2	($3,189,749)	7,589.2	
	-3	($929,610)	85.97	-3	($4,784,624)	7,620.8	
	-4	($1,239,480)	85.46	-4	($6,379,498)	7,652.4	
	-5	($1,549,350)	84.96	-5	($7,974,373)	7,684.0	
	-6	($1,859,220)	84.45	-6	($9,569,248)	7,715.6	
	-7	($2,169,090)	83.95	-7	($11,164,122)	7,747.2	
	-8	($2,478,960)	83.44	-8	($12,758,997)	7,778.9	
	-9	($2,788,830)	82.94	-9	($14,353,871)	7,810.5	
	-10	($3,098,700)	82.43	-10	($15,948,746)	7,842.1	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
3.62%	23.18%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Janauary 2015 - December 2015

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	$3,180,900	95.65	10	$7,968,053	9,884.6	
****	9.067	$2,884,122	95.29	9	$7,171,247	9,924.0	
	9	$2,862,810	95.27	8	$6,374,442	9,963.4	
	8	$2,544,720	94.89	7	$5,577,637	10,002.8	
	7	$2,226,630	94.51	6	$4,780,832	10,042.2	
	6	$1,908,540	94.13	5	$3,984,026	10,081.7	
	5	$1,590,450	93.75	4	$3,187,221	10,121.1	
	4	$1,272,360	93.37	3	$2,390,416	10,160.5	
	3	$954,270	92.99	2	$1,593,611	10,199.9	
	2	$636,180	92.62	1	$796,805	10,239.3	
	1	$318,090	92.24	0	$0	10,278.7	
		$0	91.86	0.000	$0	10,336.5	****
	0	$0	91.86	0	$0	10,353.7	
		$0	91.86	0	$0	10,428.7	
	-1	($586,050)	91.10	-1	($796,805)	10,468.1	
	-2	($1,172,100)	90.35	-2	($1,593,611)	10,507.5	
	-3	($1,758,150)	89.60	-3	($2,390,416)	10,546.9	
	-4	($2,344,200)	88.84	-4	($3,187,221)	10,586.3	
	-5	($2,930,250)	88.09	-5	($3,984,026)	10,625.7	
	-6	($3,516,300)	87.33	-6	($4,780,832)	10,665.1	
	-7	($4,102,350)	86.58	-7	($5,577,637)	10,704.5	
	-8	($4,688,400)	85.83	-8	($6,374,442)	10,743.9	
	-9	($5,274,450)	85.07	-9	($7,171,247)	10,783.3	
	-10	($5,860,500)	84.32	-10	($7,968,053)	10,822.7	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
4.62%	11.58%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Janauary 2015 - December 2015

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	$2,301,000	91.57	10	$7,213,828	9,715.0	
	10	$2,301,000	91.57	9	$6,492,445	9,751.7	
	9	$2,070,900	91.34	8	$5,771,063	9,788.5	
	8	$1,840,800	91.10	7	$5,049,680	9,825.2	
	7	$1,610,700	90.87	6	$4,328,297	9,861.9	
	6	$1,380,600	90.63	5	$3,606,914	9,898.6	
	5	$1,150,500	90.39	4	$2,885,531	9,935.4	
	4	$920,400	90.16	3	$2,164,148	9,972.1	
	3	$690,300	89.92	2.337	$1,685,872	9,996.5	****
	2	$460,200	89.69	2	$1,442,766	10,008.8	
	1	$230,100	89.45	1	$721,383	10,045.6	
		$0	89.21	0	$0	10,082.3	
	0	$0	89.21	0	$0	10,157.3	
		$0	89.21	0	$0	10,232.3	
	-1	($422,950)	88.74	-1	($721,383)	10,269.0	
	-2	($845,900)	88.26	-2	($1,442,766)	10,305.7	
	-3	($1,268,850)	87.78	-3	($2,164,148)	10,342.5	
	-4	($1,691,800)	87.30	-4	($2,885,531)	10,379.2	
	-5	($2,114,750)	86.82	-5	($3,606,914)	10,415.9	
	-6	($2,537,700)	86.34	-6	($4,328,297)	10,452.7	
	-7	($2,960,650)	85.86	-7	($5,049,680)	10,489.4	
	-8	($3,383,600)	85.38	-8	($5,771,063)	10,526.1	
	-9	($3,806,550)	84.91	-9	($6,492,445)	10,562.9	
	-10	($4,229,500)	84.43	-10	($7,213,828)	10,599.6	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
3.34%	10.49%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Janauary 2015 - December 2015

Unit: Hines 1

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$397,300	87.32	10	$7,824,023	6,823.4	
	9	$357,570	87.21	9	$7,041,621	6,860.2	
****	8.355	$331,944	87.14	8	$6,259,219	6,896.9	
	8	$317,840	87.11	7	$5,476,816	6,933.6	
	7	$278,110	87.00	6	$4,694,414	6,970.3	
	6	$238,380	86.90	5	$3,912,012	7,007.0	
	5	$198,650	86.79	4	$3,129,609	7,043.7	
	4	$158,920	86.69	3	$2,347,207	7,080.4	
	3	$119,190	86.58	2	$1,564,805	7,117.1	
	2	$79,460	86.47	1	$782,402	7,153.8	
	1	$39,730	86.37	0	$0	7,190.5	
		$0	86.26	0	$0	7,265.5	
	0	$0	86.26	0	$0	7,340.5	
		$0	86.26	-1	($782,402)	7,377.3	
	-1	($100,740)	86.05	-1.292	($1,010,864)	7,388.0	****
	-2	($201,480)	85.83	-2	($1,564,805)	7,414.0	
	-3	($302,220)	85.61	-3	($2,347,207)	7,450.7	
	-4	($402,960)	85.39	-4	($3,129,609)	7,487.4	
	-5	($503,700)	85.17	-5	($3,912,012)	7,524.1	
	-6	($604,440)	84.95	-6	($4,694,414)	7,560.8	
	-7	($705,180)	84.73	-7	($5,476,816)	7,597.5	
	-8	($805,920)	84.51	-8	($6,259,219)	7,634.2	
	-9	($906,660)	84.30	-9	($7,041,621)	7,670.9	
	-10	($1,007,400)	84.08	-10	($7,824,023)	7,707.7	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.58%	11.37%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Janauary 2015 - December 2015

Unit: Hines 2

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$430,900	89.79	10	$5,495,139	6,869.8	
	9	$387,810	89.74	9	$4,945,625	6,897.8	
	8	$344,720	89.68	8	$4,396,111	6,925.8	
	7	$301,630	89.63	7	$3,846,597	6,953.7	
	6	$258,540	89.57	6	$3,297,084	6,981.7	
	5	$215,450	89.52	5	$2,747,570	7,009.7	
	4	$172,360	89.46	4	$2,198,056	7,037.7	
	3	$129,270	89.40	3	$1,648,542	7,065.7	
	2	$86,180	89.35	2	$1,099,028	7,093.6	
	1	$43,090	89.29	1	$549,514	7,121.6	
		$0	89.24	0	$0	7,149.6	
	0	$0	89.24	0.000	$0	7,199.9	****
		$0	89.24	0	$0	7,224.6	
	-1	($40,610)	89.12	0	$0	7,299.6	
	-2	($81,220)	89.01	-1	($549,514)	7,327.6	
	-3	($121,830)	88.89	-2	($1,099,028)	7,355.6	
	-4	($162,440)	88.78	-3	($1,648,542)	7,383.5	
	-5	($203,050)	88.66	-4	($2,198,056)	7,411.5	
	-6	($243,660)	88.54	-5	($2,747,570)	7,439.5	
	-7	($284,270)	88.43	-6	($3,297,084)	7,467.5	
	-8	($324,880)	88.31	-7	($3,846,597)	7,495.5	
	-9	($365,490)	88.20	-8	($4,396,111)	7,523.4	
	-10	($406,100)	88.08	-9	($4,945,625)	7,551.4	
****	-10	($406,100)	88.08	-10	($5,495,139)	7,579.4	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.63%	7.99%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Janauary 2015 - December 2015

Unit: Hines 3

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10	$734,000	93.21	10	$9,233,745	6,679.7	
	10	$734,000	93.21	9	$8,310,370	6,719.3	
	9	$660,600	93.12	8	$7,386,996	6,759.0	
	8	$587,200	93.02	7	$6,463,621	6,798.7	
	7	$513,800	92.93	6	$5,540,247	6,838.3	
	6	$440,400	92.84	5	$4,616,872	6,878.0	
	5	$367,000	92.75	4	$3,693,498	6,917.6	
	4	$293,600	92.65	3	$2,770,123	6,957.3	
	3	$220,200	92.56	2	$1,846,749	6,997.0	
	2	$146,800	92.47	1	$923,374	7,036.6	
	1	$73,400	92.37	0	$0	7,076.3	
		$0	92.28	0.000	$0	7,167.9	****
	0	$0	92.28	0	$0	7,151.3	
		$0	92.28	0	$0	7,226.3	
	-1	($98,740)	92.09	-1	($923,374)	7,266.0	
	-2	($197,480)	91.90	-2	($1,846,749)	7,305.6	
	-3	($296,220)	91.70	-3	($2,770,123)	7,345.3	
	-4	($394,960)	91.51	-4	($3,693,498)	7,384.9	
	-5	($493,700)	91.32	-5	($4,616,872)	7,424.6	
	-6	($592,440)	91.13	-6	($5,540,247)	7,464.3	
	-7	($691,180)	90.93	-7	($6,463,621)	7,503.9	
	-8	($789,920)	90.74	-8	($7,386,996)	7,543.6	
	-9	($888,660)	90.55	-9	($8,310,370)	7,583.3	
	-10	($987,400)	90.36	-10	($9,233,745)	7,622.9	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
1.07%	13.42%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Janauary 2015 - December 2015

Unit: Hines 4

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$390,700	87.08	10	$5,185,405	6,695.3	
	9	$351,630	87.04	9	$4,666,864	6,714.7	
	8	$312,560	87.00	8	$4,148,324	6,734.1	
	7	$273,490	86.96	7	$3,629,783	6,753.5	
	6	$234,420	86.91	6	$3,111,243	6,772.9	
****	5.076	$198,319	86.88	5	$2,592,702	6,792.3	
	5	$195,350	86.87	4	$2,074,162	6,811.7	
	4	$156,280	86.83	3	$1,555,621	6,831.1	
	3	$117,210	86.79	2	$1,037,081	6,850.5	
	2	$78,140	86.75	1	$518,540	6,869.9	
	1	$39,070	86.71	0	$0	6,889.3	
		$0	86.67	0	$0	6,964.3	
	0	$0	86.67	0	$0	7,039.3	
		$0	86.67	-1	($518,540)	7,058.6	
	-1	($31,780)	86.58	-1.021	($529,430)	7,059.1	****
	-2	($63,560)	86.50	-2	($1,037,081)	7,078.0	
	-3	($95,340)	86.41	-3	($1,555,621)	7,097.4	
	-4	($127,120)	86.32	-4	($2,074,162)	7,116.8	
	-5	($158,900)	86.24	-5	($2,592,702)	7,136.2	
	-6	($190,680)	86.15	-6	($3,111,243)	7,155.6	
	-7	($222,460)	86.07	-7	($3,629,783)	7,175.0	
	-8	($254,240)	85.98	-8	($4,148,324)	7,194.4	
	-9	($286,020)	85.89	-9	($4,666,864)	7,213.8	
	-10	($317,800)	85.81	-10	($5,185,405)	7,233.2	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.57%	7.54%

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Bartow CC	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-Dec Period
1. EAF	91.68	93.44	56.55	87.01	96.37	97.94	97.50	94.49	94.48	70.72	83.23	92.21	87.89
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	669.9	591.6	406.2	614.5	726.7	692.3	716.8	690.7	670.5	516.4	585.6	680.7	7,561.7
4. RSH	12.2	36.4	14.0	12.0	0.6	14.7	13.8	12.3	15.5	9.8	14.5	5.3	160.9
5. UH	61.9	44.1	322.9	93.5	16.8	13.1	13.4	41.0	34.1	217.9	120.9	58.0	1,037.4
6. POH	58.3	0.5	222.8	80.9	0.0	0.0	0.0	0.0	18.2	217.9	120.9	0.0	719.4
7. FOH	0.0	0.0	0.0	12.6	1.5	0.7	9.6	19.2	0.0	0.0	0.0	2.5	46.1
8. MOH	3.6	43.7	100.1	0.0	15.3	12.5	3.8	21.8	15.8	0.0	0.0	55.5	272.0
9. PPOH	0.0	0.0	0.0	3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6
10. LR PP (MW)	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
11. PFOH	0.0	0.0	0.0	0.0	57.3	14.9	44.4	0.0	33.9	0.0	0.0	0.0	150.5
12. LR PF (MW)	0.0	0.0	0.0	0.0	119.1	137.6	137.5	0.0	194.0	0.0	0.0	0.0	143.2
13. PMOH	0.0	0.0	0.0	3.4	34.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.2
14. LR PM (MW)	0.0	0.0	0.0	27.0	144.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	134.0
15. NSC (MW)	1,160	1,160	1,160	1,160	1,160	1,160	1,160	1,160	1,160	1,160	1,160	1,160	1,160
16. OPER MBTU	4,903,737	4,237,148	1,079,163	3,855,124	5,375,275	5,100,215	4,394,207	4,860,370	4,583,395	2,863,630	3,901,179	5,175,751	50,329,194
17. NET GEN (MWH)	681,813	576,002	142,724	519,707	722,059	698,219	563,253	660,957	610,401	394,171	526,492	713,488	6,809,286
18. ANOHR (BTU/KWH)	7,192.2	7,356.1	7,561.2	7,417.9	7,444.4	7,304.6	7,801.5	7,353.5	7,508.8	7,264.9	7,409.8	7,254.2	7,391.3
19. NOF (%)	87.74	83.94	74.26	84.44	85.66	86.95	67.74	82.49	78.49	65.80	77.51	90.36	77.63
20. NPC (MW)	1,160	1,160	1,160	1,160	1,160	1,160	1,160	1,160	1,160	1,160	1,160	1,160	1,160
ANOHR EQUATION:	ANOHR=	-11.336	x NOF +	8,311.85									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Crystal River 4	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-Dec Period
1. EAF	90.53	99.17	98.74	96.48	89.10	93.62	99.95	98.20	99.53	95.06	83.27	100.00	95.29
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	674.9	672.0	743.0	720.0	693.0	681.8	744.0	744.0	720.0	739.7	608.8	744.0	8,485.1
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	69.1	0.0	0.0	0.0	51.1	38.2	0.0	0.0	0.0	4.3	112.2	0.0	274.9
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.3	0.0	0.0	4.3
8. MOH	69.1	0.0	0.0	0.0	51.1	38.2	0.0	0.0	0.0	0.0	112.2	0.0	270.6
9. PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. LR PP (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11. PFOH	0.0	17.4	10.3	19.7	0.0	8.3	0.0	21.4	0.0	7.1	0.0	0.0	84.1
12. LR PF (MW)	0.0	220.6	167.3	336.1	0.0	335.2	0.0	252.8	0.0	108.0	0.0	0.0	251.1
13. PMOH	10.5	1.5	18.2	128.0	238.7	34.0	4.0	20.7	35.7	174.6	31.3	0.0	697.2
14. LR PM (MW)	93.0	93.2	271.9	89.2	89.6	80.6	65.0	198.8	67.4	127.9	191.2	0.0	110.0
15. NSC (MW)	712	712	712	712	712	712	712	712	712	712	712	712	712
16. OPER MBTU	3,448,203	3,378,381	4,227,341	4,046,621	3,625,009	3,566,531	4,021,425	3,869,618	3,709,431	3,449,448	2,675,584	2,787,183	42,804,776
17. NET GEN (MWH)	332,848	319,716	412,868	398,291	351,041	349,885	380,025	359,740	354,695	332,386	244,510	253,060	4,089,065
18. ANOHR (BTU/KWH)	10,359.7	10,566.8	10,239.0	10,160.0	10,326.5	10,193.4	10,582.0	10,756.7	10,458.1	10,377.8	10,942.6	11,013.9	10,468.1
19. NOF (%)	69.26	66.82	78.04	77.69	71.15	72.08	71.74	67.91	69.19	63.11	56.41	47.77	67.68
20. NPC (MW)	712	712	712	712	712	712	712	712	712	712	712	712	712

ANOHR EQUATION: ANOHR= -8.426 x NOF + 11,055.61

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Crystal River 5	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-Dec Period
1. EAF	100.00	99.64	98.87	91.76	97.54	99.45	99.86	98.34	98.03	95.02	30.10	92.42	91.81
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	75.3	404.0	743.0	670.1	744.0	720.0	744.0	744.0	720.0	720.0	0.0	104.3	6,388.7
4. RSH	668.7	268.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	217.0	588.6	1,742.3
5. UH	0.0	0.0	0.0	49.9	0.0	0.0	0.0	0.0	0.0	24.0	504.0	51.1	629.0
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	24.0	504.0	0.0	528.0
7. FOH	0.0	0.0	0.0	49.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	51.1	101.0
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PPOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. LR PP (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11. PFOH	0.0	0.0	17.0	28.3	0.0	0.0	0.0	41.8	23.0	9.3	0.0	43.9	163.3
12. LR PF (MW)	0.0	0.0	91.0	88.4	0.0	0.0	0.0	174.5	144.5	472.0	0.0	53.0	130.9
13. PMOH	0.0	3.7	24.9	53.0	65.3	33.6	12.0	18.0	23.1	39.6	0.0	3.0	276.0
14. LR PM (MW)	0.0	471.6	177.5	78.5	199.4	83.6	63.0	80.3	292.1	124.0	0.0	472.0	149.9
15. NSC (MW)	710	710	710	710	710	710	710	710	710	710	710	710	710
16. OPER MBTU	441,979	2,042,258	4,217,136	3,835,333	4,045,552	3,716,334	3,848,861	3,799,776	3,546,606	3,273,300	0	380,185	33,147,320
17. NET GEN (MWH)	43,107	198,635	422,693	381,022	406,415	367,972	364,092	354,509	336,467	319,515	0	32,371	3,226,798
18. ANOHR (BTU/KWH)	10,253.1	10,281.5	9,976.8	10,065.9	9,954.2	10,099.5	10,571.1	10,718.4	10,540.7	10,244.6	0.0	11,744.6	10,272.5
19. NOF (%)	80.61	69.25	80.13	80.09	76.94	71.98	68.93	67.11	65.82	62.50	0.00	43.71	71.14
20. NPC (MW)	710	710	710	710	710	710	710	710	710	710	710	710	710
ANOHR EQUATION:	ANOHR=	-22.363	x NOF +	12,024.19									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Hines 1	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-Dec Period
1. EAF	99.46	71.61	0.00	43.94	95.97	100.00	95.61	98.47	100.00	100.00	99.85	96.96	83.55
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	737.1	478.5	0.0	316.3	714.0	720.0	706.5	732.2	720.0	744.0	685.1	668.2	7,221.9
4. RSH	5.2	2.8	0.0	0.0	0.0	0.0	6.5	2.4	0.0	0.0	34.9	53.2	105.0
5. UH	1.6	190.8	743.0	403.7	30.0	0.0	31.0	9.4	0.0	0.0	1.1	22.6	1,433.1
6. POH	0.0	190.8	743.0	392.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,325.8
7. FOH	0.0	0.0	0.0	11.6	1.0	0.0	31.0	9.4	0.0	0.0	1.1	22.6	76.7
8. MOH	1.6	0.0	0.0	0.0	29.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.6
9. PPOH	1.8	0.0	0.0	0.0	0.0	2.8	1.4	1.5	1.3	3.0	0.0	0.0	11.9
10. LR PP (MW)	66.0	0.0	0.0	0.0	0.0	59.1	63.7	59.8	62.2	61.4	0.0	0.0	61.7
11. PFOH	0.0	0.0	0.0	0.0	0.0	0.0	8.8	11.0	0.0	0.0	0.0	0.0	19.8
12. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	89.1	81.5	0.0	0.0	0.0	0.0	84.8
13. PMOH	15.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3
14. LR PM (MW)	72.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	72.0
15. NSC (MW)	462	462	462	462	462	462	462	462	462	462	462	462	462
16. OPER MBTU	2,524,187	1,694,595	0	1,028,254	2,150,728	2,339,254	2,318,078	2,297,932	2,297,806	2,491,592	2,185,627	2,222,709	23,550,762
17. NET GEN (MWH)	338,209	229,988	0	140,888	312,850	310,748	309,357	311,702	316,007	340,038	293,399	279,612	3,182,798
18. ANOHR (BTU/KWH)	7,463.4	7,368.2	0.0	7,298.4	6,874.6	7,527.8	7,493.2	7,372.2	7,271.4	7,327.4	7,449.3	7,949.3	7,399.4
19. NOF (%)	99.31	104.04	0.00	96.40	94.84	93.42	94.77	92.15	95.00	98.93	92.70	90.58	95.39
20. NPC (MW)	462	462	462	462	462	462	462	462	462	462	462	462	462
ANOHR EQUATION:	ANOHR=	-16.349	x NOF +	8,836.54									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Hines 2	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-Dec Period
1. EAF	0.00	0.00	0.00	0.00	0.25	47.87	100.00	100.00	100.00	97.64	100.00	100.00	54.16
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	0.0	0.0	0.0	0.0	1.8	344.7	744.0	744.0	672.1	729.9	715.0	743.1	4,694.5
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	48.0	0.0	6.0	0.9	54.9
5. UH	744.0	672.0	743.0	720.0	742.2	375.3	0.0	0.0	0.0	14.1	0.0	0.0	4,010.6
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	744.0	672.0	743.0	720.0	742.2	375.3	0.0	0.0	0.0	14.1	0.0	0.0	4,010.6
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PPOH	0.0	0.0	0.0	0.0	0.0	2.0	2.8	4.5	1.1	2.8	0.0	2.2	15.3
10. LR PP (MW)	0.0	0.0	0.0	0.0	0.0	50.9	45.9	49.1	51.4	39.5	0.0	53.0	47.8
11. PFOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.6	0.0	0.0	16.6
12. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	104.0	0.0	0.0	104.0
13. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15. NSC (MW)	490	490	490	490	490	490	490	490	490	490	490	490	490
16. OPER MBTU	0	0	0	0	1,844	1,249,778	2,495,954	2,412,473	2,054,047	2,497,869	2,302,212	2,487,713	15,501,892
17. NET GEN (MWH)	0	0	0	0	0	157,237	349,214	341,647	294,086	346,362	326,122	338,389	2,153,057
18. ANOHR (BTU/KWH)	0.0	0.0	0.0	0.0	0.0	7,948.4	7,147.3	7,061.3	6,984.5	7,211.7	7,059.4	7,351.6	7,199.9
19. NOF (%)	0.00	0.00	0.00	0.00	0.00	93.10	95.79	93.71	89.31	96.84	93.09	92.93	93.60
20. NPC (MW)	490	490	490	490	490	490	490	490	490	490	490	490	490
ANOHR EQUATION:	ANOHR=	-8.738	x NOF +	7,984.98									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Hines 3	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-Dec Period
1. EAF	97.81	100.00	100.00	59.68	68.07	100.00	98.97	100.00	99.56	100.00	98.19	92.51	92.86
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	686.9	672.0	743.0	429.7	506.4	720.0	738.2	744.0	710.2	744.0	685.5	686.2	8,066.2
4. RSH	40.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.6	0.0	22.4	2.1	72.0
5. UH	16.3	0.0	0.0	290.3	237.6	0.0	5.8	0.0	3.2	0.0	13.0	55.7	621.8
6. POH	0.0	0.0	0.0	290.3	207.7	0.0	0.0	0.0	0.0	0.0	0.0	55.7	553.7
7. FOH	16.3	0.0	0.0	0.0	29.9	0.0	5.8	0.0	0.0	0.0	13.0	0.0	64.9
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.2	0.0	0.0	0.0	3.2
9. PPOH	0.0	0.0	1.3	0.0	5.5	6.1	2.3	1.2	4.8	1.3	0.0	1.6	23.9
10. LR PP (MW)	0.0	0.0	34.4	0.0	41.3	40.0	41.6	40.1	41.4	41.3	0.0	40.3	40.5
11. PFOH	0.0	0.0	0.0	0.0	0.0	0.0	14.4	0.0	0.0	0.0	0.0	0.0	14.4
12. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	63.1	0.0	0.0	0.0	0.0	0.0	63.1
13. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.4
14. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	41.9	0.0	0.0	0.0	0.0	0.0	41.9
15. NSC (MW)	488	488	488	488	488	488	488	488	488	488	488	488	488
16. OPER MBTU	2,324,063	2,343,971	2,594,096	1,459,831	1,712,240	2,334,811	2,414,734	2,401,056	2,541,548	2,537,497	2,140,314	2,153,118	26,957,279
17. NET GEN (MWH)	327,307	336,232	367,462	204,252	224,249	329,233	340,964	340,761	325,315	353,058	310,522	304,646	3,764,001
18. ANOHR (BTU/KWH)	7,100.6	6,971.3	7,059.5	7,147.2	7,635.4	7,091.7	7,082.1	7,046.2	7,812.6	7,187.2	6,892.6	7,067.6	7,161.9
19. NOF (%)	97.64	102.53	101.35	97.40	90.74	93.70	94.64	93.85	93.87	97.24	92.82	90.98	95.62
20. NPC (MW)	488	488	488	488	488	488	488	488	488	488	488	488	488
ANOHR EQUATION:	ANOHR=	-12.705	x NOF +	8,360.08									

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ACTUAL UNIT PERFORMANCE DATA

Duke Energy Florida

Hines 4	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-Dec Period
1. EAF	100.00	100.00	100.00	95.40	98.25	99.74	100.00	100.00	100.00	25.28	68.01	78.56	88.60
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	732.4	639.2	743.0	686.9	731.0	698.0	744.0	744.0	692.3	188.1	479.8	564.9	7,643.4
4. RSH	11.6	32.8	0.0	0.0	0.0	20.3	0.0	0.0	27.8	0.0	10.6	19.6	122.6
5. UH	0.0	0.0	0.0	33.1	13.0	1.7	0.0	0.0	0.0	556.0	230.7	159.5	994.0
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	556.0	230.7	148.8	935.4
7. FOH	0.0	0.0	0.0	33.1	13.0	1.7	0.0	0.0	0.0	0.0	0.0	10.7	58.5
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PPOH	3.2	0.0	1.8	0.0	0.0	16.3	21.6	2.0	1.0	13.0	0.0	1.2	60.1
10. LR PP (MW)	50.2	0.0	41.0	0.0	0.0	34.4	33.9	39.3	39.1	32.3	0.0	39.8	35.1
11. PFOH	0.0	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0	0.0	0.0	0.0	1.1
12. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	90.0	0.0	0.0	0.0	0.0	0.0	0.0	90.0
13. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15. NSC (MW)	472	472	472	472	472	472	472	472	472	472	472	472	472
16. OPER MBTU	2,483,314	2,124,343	2,559,465	2,278,724	2,559,512	2,214,581	2,448,468	2,411,081	2,205,030	523,486	1,178,204	1,682,552	24,668,760
17. NET GEN (MWH)	359,310	308,121	367,129	319,896	339,415	308,507	347,039	345,023	315,811	69,813	171,115	248,031	3,499,210
18. ANOHR (BTU/KWH)	6,911.3	6,894.5	6,971.6	7,123.3	7,541.0	7,178.4	7,055.3	6,988.2	6,982.1	7,498.4	6,885.5	6,783.6	7,049.8
19. NOF (%)	103.94	102.13	104.69	98.67	98.37	93.64	98.82	98.25	96.65	78.65	75.56	93.03	96.99
20. NPC (MW)	472	472	472	472	472	472	472	472	472	472	472	472	472
ANOHR EQUATION:	ANOHR=	-1.879	x NOF +	7,137.27									

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PLANNED OUTAGE SCHEDULES
ACTUAL

Duke Energy Florida
Janauary 2015 - December 2015

Plant/Unit	Planned Outage Dates	Reason for Outage
Bartow 4	01/16(0241) - 02/01 (0256)	Gas Turbine - Lube Oil System
Bartow 4	3/8(0114) - 4/9 (1615)	Steam turbine valves
Bartow 4	9/26(0002) - 11/23(20:52)	Gas Turbine - Fuel Nozzles/vanes
Crystal River 5	10/30 (2359) - 11/21 (2300)	Minor Boiler Overhaul
Hines 1	2/21(0115) - 4/17(21:35)	Steam turbine & gas turbine inspection
Hines 3	4/18(1225) - 5/10(1505)	Steam turbine & gas turbine inspection
Hines 3	12/03(2000) - 12/11(1520)	Gas turbine inspection
Hines 4	10/03(0000) - 12/16(1614)	Turbine inspection, rotor replacement, balance of plant

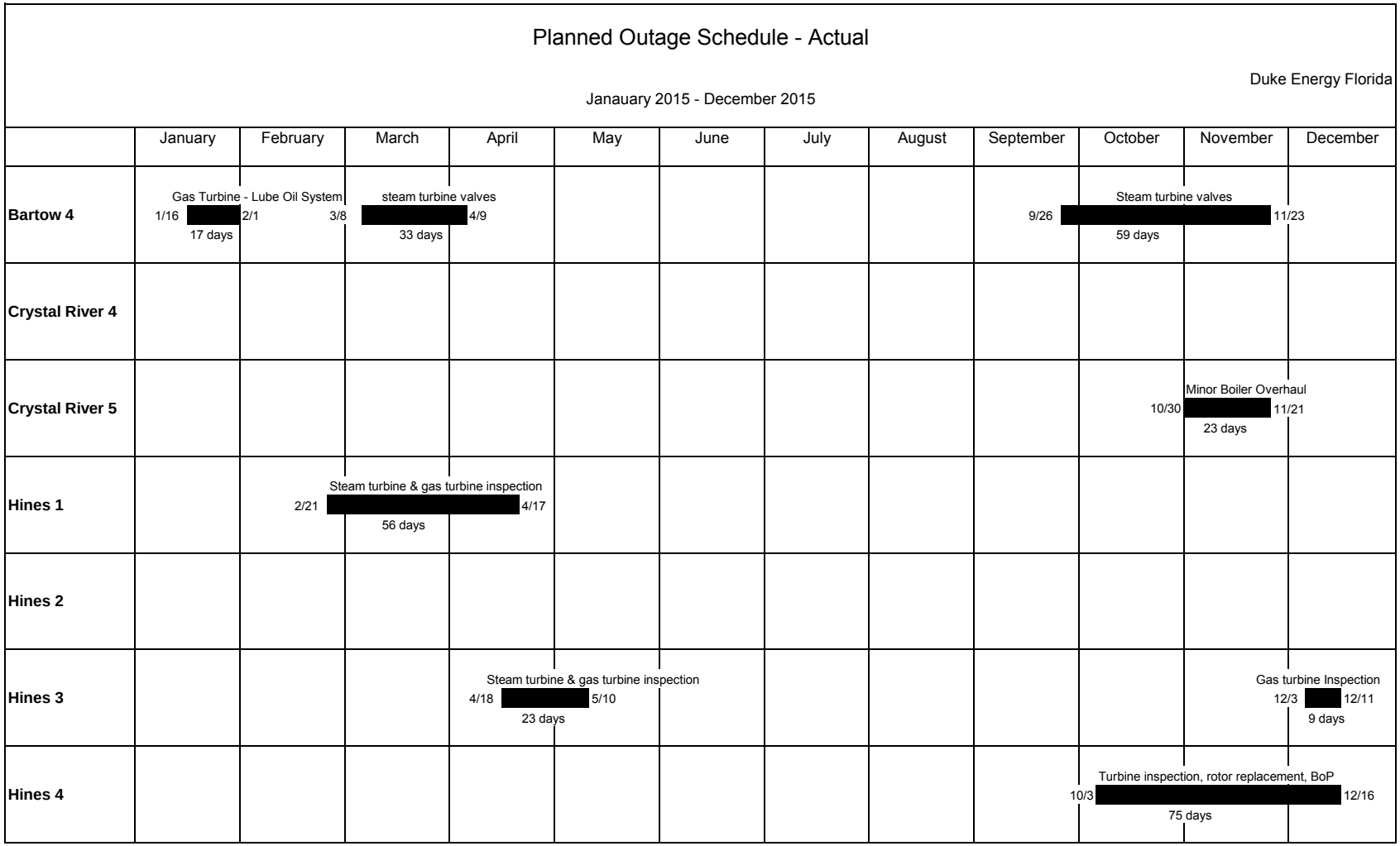
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Planned Outage Schedule - Actual

Duke Energy Florida

Janauary 2015 - December 2015



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Duke Energy Florida
Docket No. 160001-EI
Witness: Jones
Exhibit No. ____ (MJJ-1P)

GPIF Targets and Ranges for January through December 2017

STANDARD FORM GPIF SCHEDULES

Description	Page
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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 13
PARTY: DUKE ENERGY FLORIDA, LLC – (DIRECT)
DESCRIPTION: Matthew J. Jones MJJ-1P

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ESTIMATED

Duke Energy Florida
Period of: January 2017 - December 2017

Generating Performance Incentive Points (GPIF)	Fuel Saving/Loss ($)	Generating Performance Incentive Factor ($)
10	$47,836,888	$20,940,995
9	$43,053,200	$18,846,896
8	$38,269,511	$16,752,796
7	$33,485,822	$14,658,697
6	$28,702,133	$12,564,597
5	$23,918,444	$10,470,498
4	$19,134,755	$8,376,398
3	$14,351,067	$6,282,299
2	$9,567,378	$4,188,199
1	$4,783,689	$2,094,100
0	$0	$0
-1	($5,469,853)	($2,094,100)
-2	($10,939,707)	($4,188,199)
-3	($16,409,560)	($6,282,299)
-4	($21,879,413)	($8,376,398)
-5	($27,349,267)	($10,470,498)
-6	($32,819,120)	($12,564,597)
-7	($38,288,973)	($14,658,697)
-8	($43,758,826)	($16,752,796)
-9	($49,228,680)	($18,846,896)
-10	($54,698,533)	($20,940,995)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ESTIMATED

Duke Energy Florida
Period of: January 2017 - December 2017

1	Beginning of period balance of common equity	4,892,619,113	
	END OF MONTH BALANCE OF COMMON EQUITY:		
2	Month of JANUARY 2017	4,933,000,782	
3	Month of FEBRUARY 2017	4,965,848,837	
4	Month of MARCH 2017	4,998,971,578	
5	Month of APRIL 2017	5,030,260,346	
6	Month of MAY 2017	5,085,404,750	
7	Month of JUNE 2017	5,159,837,752	
8	Month of JULY 2017	5,231,976,371	
9	Month of AUGUST 2017	5,280,820,432	
10	Month of SEPTEMBER 2017	5,347,236,121	
11	Month of OCTOBER 2017	5,392,221,911	
12	Month of NOVEMBER 2017	5,420,645,622	
13	Month of DECEMBER 2017	5,456,795,848	
14	Average common equity for the period (Summation of LINE 1 through LINE 13 divided by 13)	$5,168,895,343	
15	25 Basis Points	0.0025	
16	Revenue Expansion Factor	61.3808%	
17	Maximum allowed incentive dollars (LINE 14 times LINE 15 divided by LINE 16)	$21,052,574	
18	Jurisdictional Sales	39,214,036	MWH
19	Total Sales	39,424,485	MWH
20	Jurisdictional Separation Factor (LINE 18 divided by LINE 19)	99.47%	
21	Maximum allowed jurisdictional incentive dollars (LINE 17 times LINE 20)	$20,940,995	
22	Incentive Cap (50% of Projected Fuel Savings at 10 GPIF Point Level) From Sheet No. 7.101.1	$23,918,444	
23	Maximum Allowed GPIF Reward (Lesser of Line 21 and Line 22)	$20,940,995	

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GPIF TARGET AND RANGE SUMMARY

Duke Energy Florida
Period of: January 2017 - December 2017

Plant/Unit	Weighting Factor (%)	EAF Target (%)	EAF RANGE Max. (%)	EAF RANGE Min. (%)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)
Bartow 4	3.45	90.21	92.62	85.32	1,643	(2,937)
Crystal River 4	5.04	88.23	92.41	80.01	2,398	(4,765)
Crystal River 5	2.10	88.60	90.23	85.27	1,002	(2,076)
Hines 1	0.37	91.52	92.29	89.91	178	(138)
Hines 2	5.86	67.95	80.55	41.49	2,788	(4,567)
Hines 3	0.87	87.26	89.00	83.72	413	(856)
Hines 4	0.25	89.44	91.71	84.73	117	(170)
GPIF System	17.93				8,538	(15,508)

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	19.62	7,324	90.6	6,968	7,681	9,342	(9,342)
Crystal River 4	14.25	10,255	84.8	9,814	10,697	6,784	(6,784)
Crystal River 5	14.70	9,848	85.8	9,392	10,303	7,001	(7,001)
Hines 1	9.27	7,515	83.2	7,043	7,987	4,412	(4,412)
Hines 2	5.06	7,287	89.6	6,956	7,619	2,411	(2,411)
Hines 3	10.99	7,171	97.2	6,676	7,666	5,232	(5,232)
Hines 4	8.18	7,018	99.6	6,716	7,321	3,895	(3,895)
GPIF System	82.07					39,077	(39,077)

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

Duke Energy Florida
Period of: January 2017 - December 2017

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Target POF	Target EUOF	Target EUOR	Actual Performance 1st Prior Period Jan-Jun 2016 POF	Actual Performance 1st Prior Period Jan-Jun 2016 EUOF	Actual Performance 1st Prior Period Jan-Jun 2016 EUOR	Actual Performance 2nd Prior Period Jan-Dec 2015 POF	Actual Performance 2nd Prior Period Jan-Dec 2015 EUOF	Actual Performance 2nd Prior Period Jan-Dec 2015 EUOR
Bartow 4	3.45	19.24	4.66	5.13	5.18	20.80	2.10	2.73	8.21	3.90	4.34
Crystal River 4	5.04	28.09	2.74	9.03	9.45	16.98	6.63	7.99	0.00	4.71	4.71
Crystal River 5	2.10	11.73	7.95	3.45	3.78	0.00	0.99	1.02	6.03	2.16	2.92
Hines 1	0.37	2.08	6.85	1.63	1.79	20.33	2.37	2.98	15.13	1.29	1.54
Hines 2	5.86	32.66	5.48	26.57	34.33	17.56	0.87	1.13	0.00	45.82	46.11
Hines 3	0.87	4.83	9.04	3.70	4.31	25.32	2.30	3.21	6.32	0.80	0.86
Hines 4	0.25	1.37	5.75	4.81	5.17	0.00	21.02	21.13	10.68	0.65	0.74
GPIF System Wghtd. Avg.	17.93	100.00	5.05	12.88	15.62	16.15	3.12	3.77	3.05	17.37	17.64

Plant/Unit	Actual Performance 3rd Prior Period Jan-Dec 2014 POF	Actual Performance 3rd Prior Period Jan-Dec 2014 EUOF	Actual Performance 3rd Prior Period Jan-Dec 2014 EUOR	Actual Performance 4th Prior Period Jan-Dec 2013 POF	Actual Performance 4th Prior Period Jan-Dec 2013 EUOF	Actual Performance 4th Prior Period Jan-Dec 2013 EUOR	Actual Performance 5th Prior Period Jan-Dec 2012 POF	Actual Performance 5th Prior Period Jan-Dec 2012 EUOF	Actual Performance 5th Prior Period Jan-Dec 2012 EUOR
Bartow 4	10.01	7.84	8.92	4.62	2.43	2.71	10.82	2.56	3.04
Crystal River 4	0.00	16.59	17.95	5.90	7.19	7.64	0.00	5.95	5.95
Crystal River 5	5.43	6.09	6.53	0.00	5.62	6.27	17.85	3.76	4.70
Hines 1	0.00	1.02	1.12	6.84	1.51	1.87	6.77	4.45	4.77
Hines 2	0.00	49.02	54.59	5.66	2.21	2.47	6.43	0.14	0.16
Hines 3	5.88	7.75	9.01	1.96	1.72	1.75	19.47	0.29	0.36
Hines 4	4.03	2.58	2.95	8.11	0.36	0.39	9.88	0.80	0.89
GPIF System Wghtd. Avg.	2.90	23.32	25.85	4.74	3.99	4.34	7.49	2.77	2.99

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

Duke Energy Florida
Period of: January 2017 - December 2017

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Average Heat Rate Target	1st Prior HR Jan 2015 - Dec 2015	2nd Prior HR Jan 2014 - Dec 2014	3rd Prior HR Jan 2013 - Dec 2013
Bartow 4	19.62	23.91	7,324	7,394	7,310	7,284
Crystal River 4	14.25	17.36	10,255	10,146	10,361	10,277
Crystal River 5	14.70	17.92	9,848	9,871	9,814	10,022
Hines 1	9.27	11.29	7,515	7,563	7,564	7,458
Hines 2	5.06	6.17	7,287	7,308	7,392	7,175
Hines 3	10.99	13.39	7,171	7,160	7,213	7,227
Hines 4	8.18	9.97	7,018	7,032	6,991	6,932
			-	-	-	-
			-	-	-	-
			-	-	-	-
			-	-	-	-
			-	-	-	-
GPIF System Weighted Avg.	82.07	100.00	8,253	8,262	8,277	8,572

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DERIVATION OF WEIGHTING FACTORS

Duke Energy Florida
Period of: January 2017 - December 2017

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	1,852,230	1,850,587	1,643	3.45
Bartow 4 HR	1,852,230	1,842,888	9,342	19.62
Crystal River 4 EAF	1,852,230	1,849,831	2,398	5.04
Crystal River 4 HR	1,852,230	1,845,446	6,784	14.25
Crystal River 5 EAF	1,852,230	1,851,228	1,002	2.10
Crystal River 5 HR	1,852,230	1,845,229	7,001	14.70
Hines 1 EAF	1,852,230	1,852,052	178	0.37
Hines 1 HR	1,852,230	1,847,818	4,412	9.27
Hines 2 EAF	1,852,230	1,849,441	2,788	5.86
Hines 2 HR	1,852,230	1,849,818	2,411	5.06
Hines 3 EAF	1,852,230	1,851,817	413	0.87
Hines 3 HR	1,852,230	1,846,998	5,232	10.99
Hines 4 EAF	1,852,230	1,852,113	117	0.25
Hines 4 HR	1,852,230	1,848,334	3,895	8.18

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

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2017 - December 2017

Bartow 4

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$1,642,526	92.62	10	$9,341,632	6,967.9
9	$1,478,274	92.38	9	$8,407,468	6,996.1
8	$1,314,021	92.14	8	$7,473,305	7,024.2
7	$1,149,768	91.90	7	$6,539,142	7,052.3
6	$985,516	91.66	6	$5,604,979	7,080.5
5	$821,263	91.42	5	$4,670,816	7,108.6
4	$657,011	91.18	4	$3,736,653	7,136.7
3	$492,758	90.94	3	$2,802,489	7,164.9
2	$328,505	90.70	2	$1,868,326	7,193.0
1	$164,253	90.45	1	$934,163	7,221.1
					7,249.3
0	$0	90.21	0	$0	7,324.3
					7,399.3
-1	($293,657)	89.72	-1	($934,163)	7,427.4
-2	($587,314)	89.24	-2	($1,868,326)	7,455.6
-3	($880,970)	88.75	-3	($2,802,489)	7,483.7
-4	($1,174,627)	88.26	-4	($3,736,653)	7,511.8
-5	($1,468,284)	87.77	-5	($4,670,816)	7,540.0
-6	($1,761,941)	87.28	-6	($5,604,979)	7,568.1
-7	($2,055,598)	86.79	-7	($6,539,142)	7,596.2
-8	($2,349,254)	86.30	-8	($7,473,305)	7,624.4
-9	($2,642,911)	85.81	-9	($8,407,468)	7,652.5
-10	($2,936,568)	85.32	-10	($9,341,632)	7,680.6

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
3.45%	19.62%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2017 - December 2017

Crystal River 4

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$2,398,324	92.41	10	$6,783,800	9,813.5
9	$2,158,491	91.99	9	$6,105,420	9,850.2
8	$1,918,659	91.57	8	$5,427,040	9,886.8
7	$1,678,827	91.16	7	$4,748,660	9,923.5
6	$1,438,994	90.74	6	$4,070,280	9,960.1
5	$1,199,162	90.32	5	$3,391,900	9,996.8
4	$959,329	89.90	4	$2,713,520	10,033.4
3	$719,497	89.48	3	$2,035,140	10,070.1
2	$479,665	89.07	2	$1,356,760	10,106.8
1	$239,832	88.65	1	$678,380	10,143.4
					10,180.1
0	$0	88.23	0	$0	10,255.1
					10,330.1
-1	($476,503)	87.41	-1	($678,380)	10,366.7
-2	($953,007)	86.59	-2	($1,356,760)	10,403.4
-3	($1,429,510)	85.76	-3	($2,035,140)	10,440.0
-4	($1,906,013)	84.94	-4	($2,713,520)	10,476.7
-5	($2,382,516)	84.12	-5	($3,391,900)	10,513.3
-6	($2,859,020)	83.30	-6	($4,070,280)	10,550.0
-7	($3,335,523)	82.48	-7	($4,748,660)	10,586.6
-8	($3,812,026)	81.65	-8	($5,427,040)	10,623.3
-9	($4,288,529)	80.83	-9	($6,105,420)	10,660.0
-10	($4,765,033)	80.01	-10	($6,783,800)	10,696.6

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
5.04%	14.25%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2017 - December 2017

Crystal River 5

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$1,001,687	90.23	10	$7,000,976	9,392.2
9	$901,518	90.07	9	$6,300,879	9,430.2
8	$801,349	89.90	8	$5,600,781	9,468.3
7	$701,181	89.74	7	$4,900,683	9,506.3
6	$601,012	89.58	6	$4,200,586	9,544.4
5	$500,843	89.42	5	$3,500,488	9,582.5
4	$400,675	89.25	4	$2,800,391	9,620.5
3	$300,506	89.09	3	$2,100,293	9,658.6
2	$200,337	88.93	2	$1,400,195	9,696.6
1	$100,169	88.77	1	$700,098	9,734.7
					9,772.8
0	$0	88.60	0	$0	9,847.8
					9,922.8
-1	($207,554)	88.27	-1	($700,098)	9,960.8
-2	($415,108)	87.94	-2	($1,400,195)	9,998.9
-3	($622,662)	87.60	-3	($2,100,293)	10,036.9
-4	($830,216)	87.27	-4	($2,800,391)	10,075.0
-5	($1,037,770)	86.94	-5	($3,500,488)	10,113.1
-6	($1,245,324)	86.61	-6	($4,200,586)	10,151.1
-7	($1,452,879)	86.27	-7	($4,900,683)	10,189.2
-8	($1,660,433)	85.94	-8	($5,600,781)	10,227.2
-9	($1,867,987)	85.61	-9	($6,300,879)	10,265.3
-10	($2,075,541)	85.27	-10	($7,000,976)	10,303.4

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
2.10%	14.70%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2017 - December 2017

Hines 1

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$177,545	92.29	10	$4,411,985	7,042.6
9	$159,790	92.21	9	$3,970,786	7,082.3
8	$142,036	92.14	8	$3,529,588	7,122.0
7	$124,281	92.06	7	$3,088,389	7,161.7
6	$106,527	91.98	6	$2,647,191	7,201.4
5	$88,772	91.90	5	$2,205,992	7,241.1
4	$71,018	91.83	4	$1,764,794	7,280.8
3	$53,263	91.75	3	$1,323,595	7,320.5
2	$35,509	91.67	2	$882,397	7,360.2
1	$17,754	91.60	1	$441,198	7,399.9
					7,439.6
0	$0	91.52	0	$0	7,514.6
					7,589.6
-1	($13,754)	91.36	-1	($441,198)	7,629.3
-2	($27,509)	91.20	-2	($882,397)	7,669.0
-3	($41,263)	91.04	-3	($1,323,595)	7,708.7
-4	($55,018)	90.88	-4	($1,764,794)	7,748.4
-5	($68,772)	90.71	-5	($2,205,992)	7,788.1
-6	($82,527)	90.55	-6	($2,647,191)	7,827.8
-7	($96,281)	90.39	-7	($3,088,389)	7,867.5
-8	($110,036)	90.23	-8	($3,529,588)	7,907.2
-9	($123,790)	90.07	-9	($3,970,786)	7,946.9
-10	($137,545)	89.91	-10	($4,411,985)	7,986.6

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.37%	9.27%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2017 - December 2017

Hines 2

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$2,788,133	80.55	10	$2,411,093	6,955.8
9	$2,509,320	79.29	9	$2,169,983	6,981.4
8	$2,230,506	78.03	8	$1,928,874	7,007.1
7	$1,951,693	76.77	7	$1,687,765	7,032.8
6	$1,672,880	75.51	6	$1,446,656	7,058.4
5	$1,394,066	74.25	5	$1,205,546	7,084.1
4	$1,115,253	72.99	4	$964,437	7,109.7
3	$836,440	71.73	3	$723,328	7,135.4
2	$557,627	70.47	2	$482,219	7,161.0
1	$278,813	69.21	1	$241,109	7,186.7
					7,212.4
0	$0	67.95	0	$0	7,287.4
					7,362.4
-1	($456,690)	65.30	-1	($241,109)	7,388.0
-2	($913,379)	62.66	-2	($482,219)	7,413.7
-3	($1,370,069)	60.01	-3	($723,328)	7,439.3
-4	($1,826,758)	57.37	-4	($964,437)	7,465.0
-5	($2,283,448)	54.72	-5	($1,205,546)	7,490.6
-6	($2,740,137)	52.07	-6	($1,446,656)	7,516.3
-7	($3,196,827)	49.43	-7	($1,687,765)	7,541.9
-8	($3,653,516)	46.78	-8	($1,928,874)	7,567.6
-9	($4,110,206)	44.14	-9	($2,169,983)	7,593.3
-10	($4,566,896)	41.49	-10	($2,411,093)	7,618.9

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
5.86%	5.06%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2017 - December 2017

Hines 3

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$412,697	89.00	10	$5,231,629	6,675.8
9	$371,427	88.83	9	$4,708,467	6,717.8
8	$330,158	88.65	8	$4,185,304	6,759.8
7	$288,888	88.48	7	$3,662,141	6,801.8
6	$247,618	88.31	6	$3,138,978	6,843.8
5	$206,349	88.13	5	$2,615,815	6,885.8
4	$165,079	87.96	4	$2,092,652	6,927.8
3	$123,809	87.78	3	$1,569,489	6,969.9
2	$82,539	87.61	2	$1,046,326	7,011.9
1	$41,270	87.44	1	$523,163	7,053.9
					7,095.9
0	$0	87.26	0	$0	7,170.9
					7,245.9
-1	($85,611)	86.91	-1	($523,163)	7,287.9
-2	($171,221)	86.55	-2	($1,046,326)	7,329.9
-3	($256,832)	86.20	-3	($1,569,489)	7,371.9
-4	($342,443)	85.85	-4	($2,092,652)	7,413.9
-5	($428,054)	85.49	-5	($2,615,815)	7,455.9
-6	($513,664)	85.14	-6	($3,138,978)	7,497.9
-7	($599,275)	84.78	-7	($3,662,141)	7,539.9
-8	($684,886)	84.43	-8	($4,185,304)	7,581.9
-9	($770,497)	84.07	-9	($4,708,467)	7,623.9
-10	($856,107)	83.72	-10	($5,231,629)	7,665.9

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.87%	10.99%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Duke Energy Florida
Period of: January 2017 - December 2017

Hines 4

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$116,833	91.71	10	$3,895,411	6,715.6
9	$105,150	91.48	9	$3,505,870	6,738.4
8	$93,467	91.25	8	$3,116,329	6,761.2
7	$81,783	91.03	7	$2,726,788	6,784.0
6	$70,100	90.80	6	$2,337,247	6,806.8
5	$58,417	90.57	5	$1,947,706	6,829.6
4	$46,733	90.34	4	$1,558,165	6,852.3
3	$35,050	90.12	3	$1,168,623	6,875.1
2	$23,367	89.89	2	$779,082	6,897.9
1	$11,683	89.66	1	$389,541	6,920.7
					6,943.5
0	$0	89.44	0	$0	7,018.5
					7,093.5
-1	($16,982)	88.97	-1	($389,541)	7,116.3
-2	($33,964)	88.49	-2	($779,082)	7,139.1
-3	($50,946)	88.02	-3	($1,168,623)	7,161.9
-4	($67,928)	87.55	-4	($1,558,165)	7,184.6
-5	($84,910)	87.08	-5	($1,947,706)	7,207.4
-6	($101,892)	86.61	-6	($2,337,247)	7,230.2
-7	($118,873)	86.14	-7	($2,726,788)	7,253.0
-8	($135,855)	85.67	-8	($3,116,329)	7,275.8
-9	($152,837)	85.20	-9	($3,505,870)	7,298.6
-10	($169,819)	84.73	-10	($3,895,411)	7,321.4

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.25%	8.18%

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UNIT PERFORMANCE DATA

ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2017 - December 2017

PLANT/UNIT **Bartow 4**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	94 86	95.03	71.52	94 85	94 86	94.85	94.83	94.85	94.85	70.64	87 36	94 87	90.21
2. POF	0 00	0.00	23.39	0 00	0 00	0.00	0.00	0.00	0.00	24.19	7.50	0 00	4.66
3. EUOF	5.14	4.97	5.09	5.15	5.14	5.15	5.17	5.15	5.15	5.16	5.14	5.13	5.13
4. EUOR	5.18	5.18	5.18	5.18	5.18	5.18	5.18	5.18	5.18	5.18	5.18	5.18	5.18
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	700 8	612.3	694.4	679.7	700.9	679.7	704.7	702.8	679.4	704 3	679.1	699.9	8,238.1
7. RSH	6 8	27.9	13.5	5 0	6.7	5.0	2.7	4.7	5 3	3.1	5 6	7.7	94.0
8. UH	36.4	31.8	36.1	35 3	36.4	35.3	36.6	36.5	35 3	36 6	35 3	36.4	427.9
9. POH & PPOH	0 0	0.0	174.0	0 0	0.0	0.0	0.0	0.0	0 0	180 0	54 0	0 0	408.0
10. FOH & PFOH	25 3	22.1	25.1	24 6	25.3	24.6	25.5	25.4	24 6	25.5	24.5	25 3	297.8
11. MOH & PMOH	12.9	11.3	12.8	12.5	12.9	12.5	13.0	12.9	12.5	13 0	12.5	12.9	151.5
12. Oper. Btu(MBtu)	5,132,623	4,596,839	4,328,178	5,075,960	5,192,600	5,164,164	5,360,908	5,289,404	5,017,789	5,117,890	4,901,655	5,187,144	60,379,881
13. Net Gen. (MWH)	700,717 0	629,129.0	582,473 0	694,330 0	709,714.0	707,641.0	734,697.0	724,098 0	685,608 0	698,166 0	668,230 0	708,990.0	8,243,793 0
14. ANOHR (Btu/KWH)	7,325	7,307	7,431	7,311	7,316	7,298	7,297	7,305	7,319	7,330	7,335	7,316	7,324
15. NOF (%)	90.5	93.0	75.9	92.4	91.6	94.2	94.4	93.2	91 3	89.7	89 0	91.7	90.6
16. NSC (MW)	1105	1105	1105	1105	1105	1105	1105	1105	1105	1105	1105	1105	1105
17. ANOHR Equation	ANOHR=	-7.262 x NOF +		7,981.9									

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ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2017 - December 2017

PLANT/UNIT **Crystal River 4**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	90.75	91.23	90.68	60 62	90 69	90.66	90.57	90.63	90.63	90.67	90.56	90 69	88.23
2. POF	0 00	0.00	0.00	33 33	0 00	0.00	0.00	0.00	0.00	0.00	0 00	0 00	2.74
3. EUOF	9 25	8.77	9.32	6 05	9 31	9.34	9.43	9.37	9.37	9.33	9.44	9 31	9.03
4. EUOR	9.45	9.45	9.45	9.45	9.45	9.45	9.45	9.45	9.45	9.45	9.45	9.45	9.45
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	667.4	571.6	672.4	422 2	671.8	652.0	680.6	676.2	654 2	673.5	659 2	671 8	7,673.1
7. RSH	15 6	48.2	10.2	19 2	10.8	8.4	1.2	6.0	6 0	9 0	0 6	10 8	146.0
8. UH	61 0	52.2	61.4	278 6	61.4	59.6	62.2	61.8	59 8	61.5	60 2	61.4	940.9
9. POH & PPOH	0 0	0.0	0.0	240 0	0.0	0.0	0.0	0.0	0 0	0 0	0 0	0 0	240.0
10. FOH & PFOH	30.1	25.8	30.3	19 0	30.3	29.4	30.7	30.5	29.5	30.4	29.7	30 3	346.2
11. MOH & PMOH	38.7	33.1	39.0	24.5	39.0	37.8	39.5	39.2	37.9	39.1	38 2	39 0	445.0
12. Oper. Btu(MBtu)	3,663,857	3,262,864	4,069,682	2,467,695	4,077,972	4,306,487	4,742,431	4,429,155	4,263,148	4,339,084	3,978,794	3,847,359	47,505,015
13. Net Gen. (MWH)	349,411 0	313,282.0	395,054 0	237,951 0	396,081.0	425,836.0	474,997.0	437,139 0	420,271 0	426,689 0	386,022 0	369,613.0	4,632,346 0
14. ANOHR (Btu/KWH)	10,486	10,415	10,302	10,371	10,296	10,113	9,984	10,132	10,144	10,169	10,307	10,409	10,255
15. NOF (%)	73.5	77.0	82.5	79 2	82.8	91.7	98.0	90.8	90 2	89 0	82 2	77 3	84.8
16. NSC (MW)	712	712	712	712	712	712	712	712	712	712	712	712	712
17. ANOHR Equation	ANOHR=	-20.485 x NOF +		11,992.1									

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ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2017 - December 2017

PLANT/UNIT **Crystal River 5**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	96 22	96.38	96.23	96 22	96 26	96.25	96.24	96.23	96.24	37.25	64 21	96 22	88.60
2. POF	0 00	0.00	0.00	0 00	0 00	0.00	0.00	0.00	0.00	61.29	33 33	0 00	7.95
3. EUOF	3.78	3.62	3.77	3.78	3.74	3.75	3.76	3.77	3.76	1.46	2.45	3.78	3.45
4. EUOR	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	722.4	626.2	721.8	699.1	715.4	694.4	720.0	721.2	696.1	279.9	454 2	723 0	7,773.5
7. RSH	0 6	27.6	1.2	0 6	7.8	5.4	3.0	1.8	3 6	0 0	12 6	0 0	64.2
8. UH	21 0	18.2	21.0	20 3	20.8	20.2	21.0	21.0	20 3	464.1	253 2	21 0	922.3
9. POH & PPOH	0 0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0 0	456 0	240 0	0 0	696.0
10. FOH & PFOH	13 3	11.5	13.2	12 8	13.1	12.7	13.2	13.2	12 8	5.1	8 3	13 3	142.6
11. MOH & PMOH	14 8	12.9	14.8	14.4	14.7	14.3	14.8	14.8	14 3	5.7	9 3	14 8	159.7
12. Oper. Btu(MBtu)	4,363,230	3,762,757	4,304,942	4,116,677	4,105,100	4,004,855	4,462,949	4,433,618	4,247,788	1,762,917	2,634,685	4,444,776	46,660,411
13. Net Gen. (MWH)	444,040 0	382,240.0	436,186 0	415,323 0	410,695.0	401,308.0	458,476.0	454,076 0	433,866 0	182,229 0	264,500 0	455,234.0	4,738,173 0
14. ANOHR (Btu/KWH)	9,826	9,844	9,870	9,912	9,995	9,980	9,734	9,764	9,791	9,674	9,961	9,764	9,848
15. NOF (%)	86 6	86.0	85.1	83.7	80.9	81.4	89.7	88.7	87 8	91.7	82 0	88.7	85.8
16. NSC (MW)	710	710	710	710	710	710	710	710	710	710	710	710	710
17. ANOHR Equation	ANOHR=	-29.604 x NOF +		12,389 2									

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ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2017 - December 2017

PLANT/UNIT **Hines 1**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	98 28	84.34	31.70	98 21	98 21	98.22	98.21	98.21	98.21	98.22	98 29	98 30	91.52
2. POF	0 00	14.29	67.74	0 00	0 00	0.00	0.00	0.00	0.00	0.00	0 00	0 00	6.85
3. EUOF	1.72	1.37	0.56	1.79	1.79	1.78	1.79	1.79	1.79	1.78	1.71	1.70	1.63
4. EUOR	1.79	1.79	1.79	1.79	1.79	1.79	1.79	1.79	1.79	1.79	1.79	1.79	1.79
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	702 8	508.3	228.5	707.5	730.8	706.6	731.9	731.3	710.5	730 3	677.9	697.7	7,864.2
7. RSH	31 8	60.9	8.4	3.1	3.4	4.0	2.3	2.9	0 0	4 0	33 0	37 0	190.8
8. UH	9.4	102.8	507.1	9.4	9.8	9.4	9.8	9.8	9.5	9.7	9.1	9 3	705.0
9. POH & PPOH	0 0	96.0	504.0	0 0	0.0	0.0	0.0	0.0	0 0	0 0	0 0	0 0	600.0
10. FOH & PFOH	9 2	6.6	3.0	9 2	9.5	9.2	9.5	9.5	9 3	9.5	8 8	9.1	102.5
11. MOH & PMOH	3 6	2.6	1.2	3 6	3.8	3.6	3.8	3.8	3.7	3 8	3.5	3 6	40.5
12. Oper. Btu(MBtu)	2,357,179	1,768,298	754,457	2,287,635	2,261,550	2,254,316	2,294,509	2,335,995	2,300,578	2,386,145	2,159,177	2,253,064	25,418,552
13. Net Gen. (MWH)	316,292 0	239,364.0	100,868 0	304,453 0	298,222.0	299,155.0	303,370.0	310,069 0	306,264 0	318,292 0	286,422 0	299,766.0	3,382,537 0
14. ANOHR (Btu/KWH)	7,453	7,387	7,480	7,514	7,583	7,536	7,563	7,534	7,512	7,497	7,538	7,516	7,515
15. NOF (%)	87 0	91.1	85.4	83 2	78.9	81.9	80.2	82.0	83.4	84 3	81.7	83.1	83.2
16. NSC (MW)	517	517	517	517	517	517	517	517	517	517	517	517	517
17. ANOHR Equation	ANOHR=	-16.120 x NOF +		8,855 8									

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ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2017 - December 2017

PLANT/UNIT **Hines 2**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	78.11	82.53	70.00	66 22	26 35	67.96	67.33	67.33	67.53	66.98	77 03	79 67	67.95
2. POF	0 00	0.00	0.00	3 33	61 29	0.00	0.00	0.00	0.00	0.00	0 00	0 00	5.48
3. EUOF	21 89	17.47	30.00	30.44	12 36	32.04	32.67	32.67	32.47	33.02	22.97	20 33	26.57
4. EUOR	34 33	34.33	34.33	34 33	34 33	34.33	34.33	34.33	34.33	34.33	34 33	34 33	34.33
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	311 8	224.8	427.4	419.7	176.1	441.7	465.4	465.4	447 6	470.4	316 6	289 6	4,456.5
7. RSH	269.7	330.0	93.9	57 6	20.2	48.1	36.1	36.1	39.1	28.4	238.4	303.5	1501.1
8. UH	162.5	117.2	222.7	242.7	547.7	230.2	242.5	242.5	233 3	245 2	165 0	150.9	2802.4
9. POH & PPOH	0 0	0.0	0.0	24 0	456.0	0.0	0.0	0.0	0 0	0 0	0 0	0 0	480.0
10. FOH & PFOH	162.5	117.2	222.8	218 8	91.8	230.2	242.6	242.6	233 3	245 2	165 0	150.9	2322.9
11. MOH & PMOH	0 3	0.2	0.4	0.4	0.2	0.5	0.5	0.5	0.5	0.5	0 3	0 3	4.6
12. Oper. Btu(MBtu)	969,151	757,874	1,429,739	1,519,455	617,044	1,539,065	1,759,061	1,771,140	1,667,681	1,889,119	1,037,970	880,126	15,863,805
13. Net Gen. (MWH)	129,558 0	102,838.0	193,718 0	209,279 0	84,394.0	210,242.0	244,703.0	246,791 0	231,198 0	266,868 0	140,095 0	117,211.0	2,176,895 0
14. ANOHR (Btu/KWH)	7,480	7,370	7,381	7,260	7,311	7,320	7,189	7,177	7,213	7,079	7,409	7,509	7,287
15. NOF (%)	76 2	83.9	83.2	91.5	88.0	87.3	96.5	97.3	94 8	104.1	81 2	74 3	89.6
16. NSC (MW)	545	545	545	545	545	545	545	545	545	545	545	545	545
17. ANOHR Equation	ANOHR=	-14.421 x NOF +		8,579.9									

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ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2017 - December 2017

PLANT/UNIT **Hines 3**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	96 34	96.28	77.24	9 62	95.74	95.71	95.71	95.74	95.74	95.73	96 31	96 23	87.26
2. POF	0 00	0.00	19.35	90 00	0 00	0.00	0.00	0.00	0.00	0.00	0 00	0 00	9.04
3. EUOF	3 66	3.72	3.41	0 38	4 26	4.29	4.29	4.26	4.26	4.27	3 69	3.77	3.70
4. EUOR	4 31	4.31	4.31	4 31	4 31	4.31	4.31	4.31	4.31	4.31	4 31	4 31	4.31
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	606 6	556.8	564.4	61 2	705.5	688.1	709.9	705.2	683.1	707 0	591.4	624.9	7,204.2
7. RSH	111 0	91.0	11.1	8.1	7.8	2.0	3.2	8.1	7 2	6 3	102.9	91.9	450.6
8. UH	26.4	24.2	168.5	650.7	30.7	29.9	30.9	30.7	29.7	30.7	25.7	27 2	1105.2
9. POH & PPOH	0 0	0.0	144.0	648 0	0.0	0.0	0.0	0.0	0 0	0 0	0 0	0 0	792.0
10. FOH & PFOH	11 2	10.3	10.4	1.1	13.1	12.7	13.1	13.1	12 6	13.1	10.9	11 6	133.3
11. MOH & PMOH	16 0	14.7	14.9	1 6	18.6	18.2	18.8	18.6	18.1	18.7	15 6	16.5	190.4
12. Oper. Btu(MBtu)	2,235,252	2,192,525	2,075,886	222,191	2,686,556	2,719,882	2,749,985	2,629,818	2,630,713	2,693,431	2,126,668	2,312,308	27,276,146
13. Net Gen. (MWH)	311,375 0	306,253.0	289,155 0	30,933 0	374,736.0	379,976.0	383,854.0	366,512 0	367,117 0	375,703 0	295,969 0	322,162.0	3,803,745 0
14. ANOHR (Btu/KWH)	7,179	7,159	7,179	7,183	7,169	7,158	7,164	7,175	7,166	7,169	7,185	7,177	7,171
15. NOF (%)	94.5	101.3	94.4	93 0	97.8	101.7	99.6	95.7	99 0	97.9	92 2	94.9	97.2
16. NSC (MW)	543	543	543	543	543	543	543	543	543	543	543	543	543
17. ANOHR Equation	ANOHR=	-2.875 x NOF +		7,450.4									

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ESTIMATED UNIT PERFORMANCE DATA

Duke Energy Florida
Period of: January 2017 - December 2017

PLANT/UNIT **Hines 4**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	94.91	95.06	94.86	94 88	94 88	94.86	94.87	94.85	91.71	33.71	94 89	94 88	89.44
2. POF	0 00	0.00	0.00	0 00	0 00	0.00	0.00	0.00	3.33	64.52	0 00	0 00	5.75
3. EUOF	5 09	4.94	5.14	5.12	5.12	5.14	5.13	5.15	4.96	1.77	5.11	5.12	4.81
4. EUOR	5.17	5.17	5.17	5.17	5.17	5.17	5.17	5.17	5.17	5.17	5.17	5.17	5.17
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	697 0	611.4	704.8	678.7	701.7	681.1	703.2	705.6	657.9	242.5	677.9	701.1	7,762.8
7. RSH	11 8	29.7	3.6	7 0	6.9	4.5	5.3	2.8	4.9	9 2	7.9	7.5	101.1
8. UH	35 2	30.9	35.6	34 3	35.4	34.4	35.5	35.6	57 2	492 3	34 2	35.4	896.1
9. POH & PPOH	0 0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	24 0	480 0	0 0	0 0	504.0
10. FOH & PFOH	34.4	30.2	34.8	33.5	34.7	33.7	34.8	34.9	32.5	12 0	33.5	34 6	383.6
11. MOH & PMOH	3.4	3.0	3.4	3 3	3.4	3.3	3.4	3.4	3 2	1 2	3 3	3.4	37.8
12. Oper. Btu(MBtu)	2,562,772	2,373,796	2,573,246	2,410,515	2,541,696	2,537,894	2,598,535	2,640,910	2,439,662	905,821	2,475,865	2,533,819	28,595,506
13. Net Gen. (MWH)	365,099 0	339,496.0	366,413 0	342,602 0	361,726.0	361,891.0	370,323.0	376,700 0	347,767 0	129,186 0	352,556 0	360,549.0	4,074,308 0
14. ANOHR (Btu/KWH)	7,019	6,992	7,023	7,036	7,027	7,013	7,017	7,011	7,015	7,012	7,023	7,028	7,018
15. NOF (%)	99.4	105.4	98.6	95 8	97.8	100.8	99.9	101.3	100 3	101.1	98.7	97 6	99.6
16. NSC (MW)	527	527	527	527	527	527	527	527	527	527	527	527	527
17. ANOHR Equation	ANOHR=	-4.571 x NOF +		7,473.7									

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PLANNED OUTAGE SCHEDULES

Duke Energy Florida
Period of: January 2017 - December 2017

Plant/Unit	Planned Outage Dates	Reason for Outage
Bartow 4	03/15 (0001) - 03/17 (2400)	STM condenser cleaning, plus boroscopes A&C;
Bartow 4	10/22 (0001) - 11/03 (2400)	Boroscope B&D
Crystal River 4	4/21 (0001) - 4/30 (2400)	FLEX
Crystal River 5	10/13 (0001) - 11/10 (2400)	Balance of Plant
Hines 1	02/25 (0001) - 03/21 (2400)	HGP (A)(B), Balance of Plant
Hines 2	04/30(0001) - 05/19 (2400)	Balance of Plant
Hines 3	03/26(0001) - 04/27 (2400)	Controls Upgrade,HGP/RCIE, BOP, Gen. Insp
Hines 4	09/30 (0001) - 10/20 (2400)	Balance of Plant

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AVERAGE NET OPERATING HEAT RATE CURVES

DUKE ENERGY FLORIDA

Bartow Unit 4

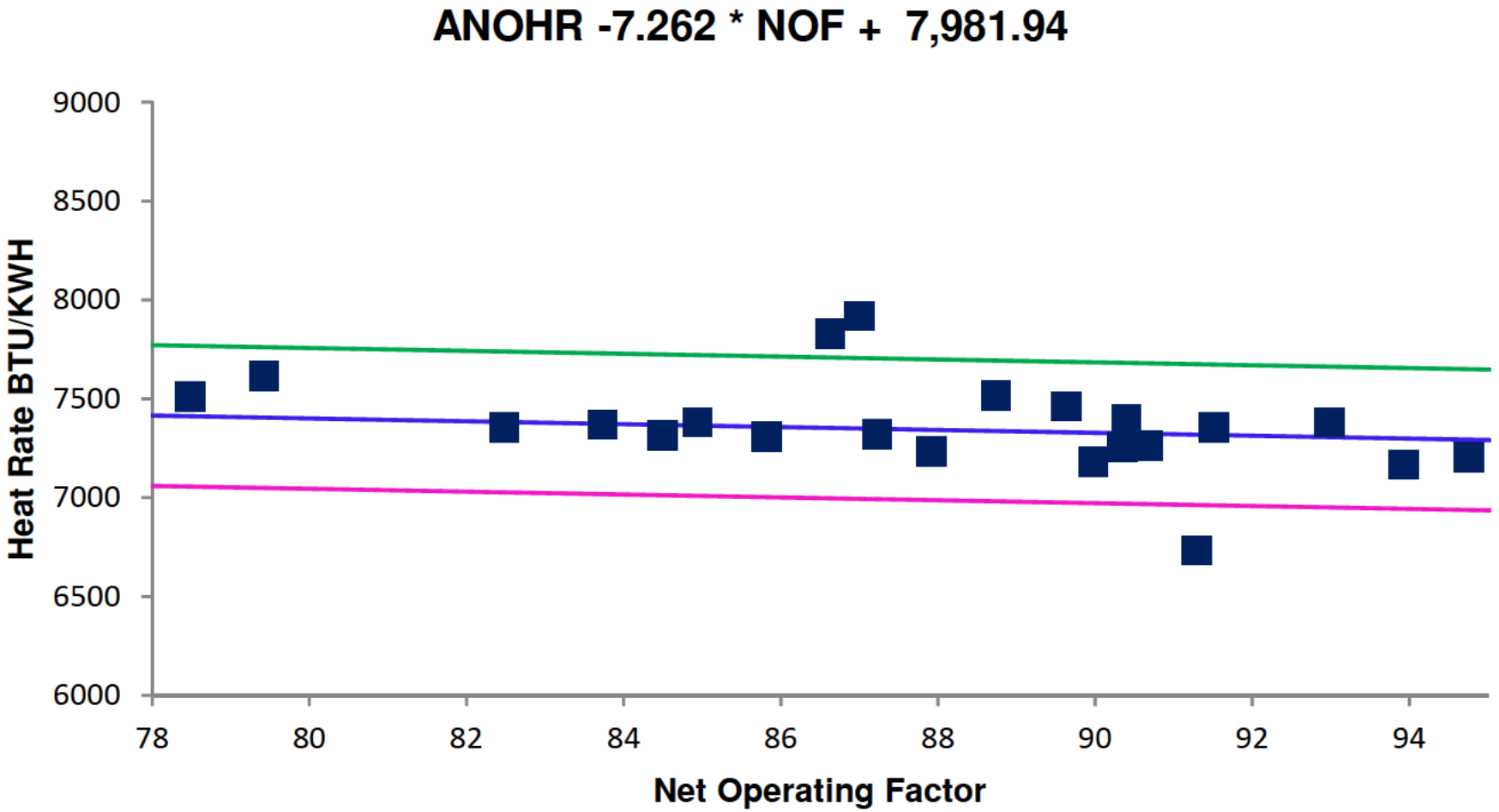
ANOHR -7.262 * NOF + 7,981.94

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-13	88.8	7,514	7,337	176.2	356.3
Aug-13	90.7	7,260	7,323	-63.1	356.3
Sep-13	83.7	7,367	7,374	-6.7	356.3
Oct-13	87.9	7,229	7,343	-114.0	356.3
Nov-13	90.0	7,177	7,328	-151.3	356.3
Dec-13	94.8	7,204	7,294	-89.9	356.3
Jan-14	93.9	7,164	7,300	-135.3	356.3
Feb-14	90.6	7,262	7,324	-62.3	356.3
Mar-14	87.2	7,319	7,348	-29.2	356.3
Jun-14	86.6	7,826	7,353	472.8	356.3
Jul-14	89.6	7,460	7,331	129.1	356.3
Aug-14	91.3	6,731	7,319	-588.1	356.3
Sep-14	90.4	7,393	7,325	67.9	356.3
Oct-14	91.5	7,352	7,317	34.8	356.3
Jan-15	84.5	7,311	7,368	-57.7	356.3
Feb-15	79.4	7,610	7,405	204.5	356.3
Apr-15	101.0	7,172	7,248	-76.2	356.3
May-15	87.0	7,916	7,350	565.8	356.3
Jun-15	93.0	7,377	7,307	70.2	356.3
Jul-15	67.7	7,801	7,490	311.5	356.3
Aug-15	82.5	7,354	7,383	-29.4	356.3
Sep-15	78.5	7,509	7,412	96.9	356.3
Oct-15	65.8	7,265	7,504	-239.2	356.3
Nov-15	77.5	7,410	7,419	-9.3	356.3
Dec-15	90.4	7,254	7,326	-71.6	356.3
Jan-16	85.0	7,378	7,365	12.6	356.3
Feb-16	85.8	7,305	7,359	-53.5	356.3
Mar-16	76.6	7,205	7,426	-220.3	356.3
Apr-16	47.1	7,494	7,640	-145.3	356.3

Regression Output:

Constant	7981.94
Std Err of Y Est	220.4559755
R Squared	0.110422602
No. of Observations	29
Degrees of Freedom	27
X Coefficient	-7.262072159
Std Err of Coef.	3.966811469


ANOHR -7.262 * NOF + 7,981.94
Heat Rate BTU/KWH
9000
8500
8000
7500
7000
6500
6000
78
80
82
84
86
88
90
92
94
Net Operating Factor

DUKE ENERGY FLORIDA

Crystal River Unit 4

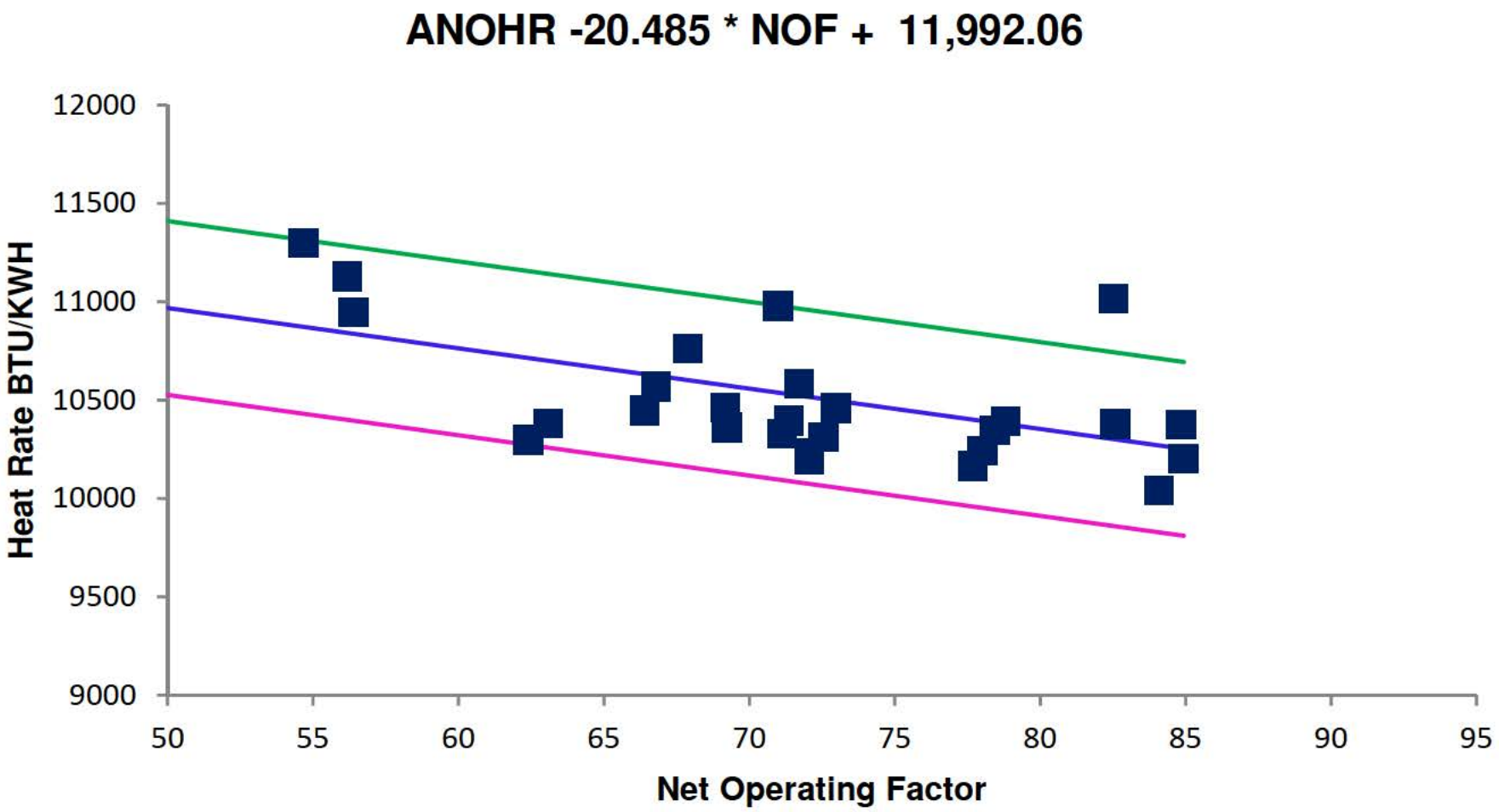
ANOHR -20.485 * NOF + 11,992.06

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-13	71.0	10,975	10,537	437.9	441.5
Aug-13	73.0	10,456	10,497	-40.8	441.5
Sep-13	71.4	10,395	10,530	-134.9	441.5
Oct-13	72.1	10,225	10,515	-290.0	441.5
Nov-13	66.4	10,443	10,631	-188.1	441.5
Dec-13	72.6	10,308	10,505	-197.7	441.5
Jan-14	84.9	10,373	10,253	119.6	441.5
Feb-14	78.8	10,390	10,377	13.2	441.5
Mar-14	82.6	10,374	10,300	74.2	441.5
Apr-14	84.9	10,198	10,252	-53.9	441.5
May-14	84.1	10,039	10,269	-230.0	441.5
Jun-14	82.5	11,012	10,301	710.7	441.5
Jul-14	84.9	10,373	10,253	119.6	441.5
Aug-14	78.8	10,390	10,377	13.2	441.5
Sep-14	82.6	10,374	10,300	74.2	441.5
Oct-14	84.9	10,198	10,252	-53.9	441.5
Nov-14	84.1	10,039	10,269	-230.0	441.5
Dec-14	82.5	11,012	10,301	710.7	441.5
Jan-15	69.3	10,360	10,573	-213.4	441.5
Feb-15	66.8	10,567	10,623	-56.4	441.5
Mar-15	78.0	10,239	10,393	-154.3	441.5
Apr-15	77.7	10,160	10,400	-240.5	441.5
May-15	71.2	10,326	10,535	-208.1	441.5
Jun-15	72.1	10,193	10,516	-322.1	441.5
Jul-15	71.7	10,582	10,522	59.6	441.5
Aug-15	67.9	10,757	10,601	155.8	441.5
Sep-15	69.2	10,458	10,575	-116.6	441.5
Oct-15	63.1	10,378	10,699	-321.4	441.5
Nov-15	56.4	10,943	10,836	106.2	441.5
Dec-15	47.8	11,014	11,013	0.5	441.5
Jan-16	54.7	11,297	10,872	425.0	441.5
Feb-16	48.6	11,206	10,996	209.9	441.5
Apr-16	62.4	10,294	10,713	-419.8	441.5
May-16	56.2	11,124	10,841	282.3	441.5
Jun-16	78.5	10,344	10,385	-40.7	441.5

Regression Output:

Constant	11992.06
Std Err of Y Est	272.3337232
R Squared	0.394229053
No. of Observations	35
Degrees of Freedom	33
X Coefficient	-20.4854349
Std Err of Coef.	4.420466724


ANOHR -20.485 * NOF + 11,992.06
Heat Rate BTU/KWH
12000
11500
11000
10500
10000
9500
9000
50
55
60
65
70
75
80
85
90
95
Net Operating Factor

DUKE ENERGY FLORIDA

Crystal River Unit 5

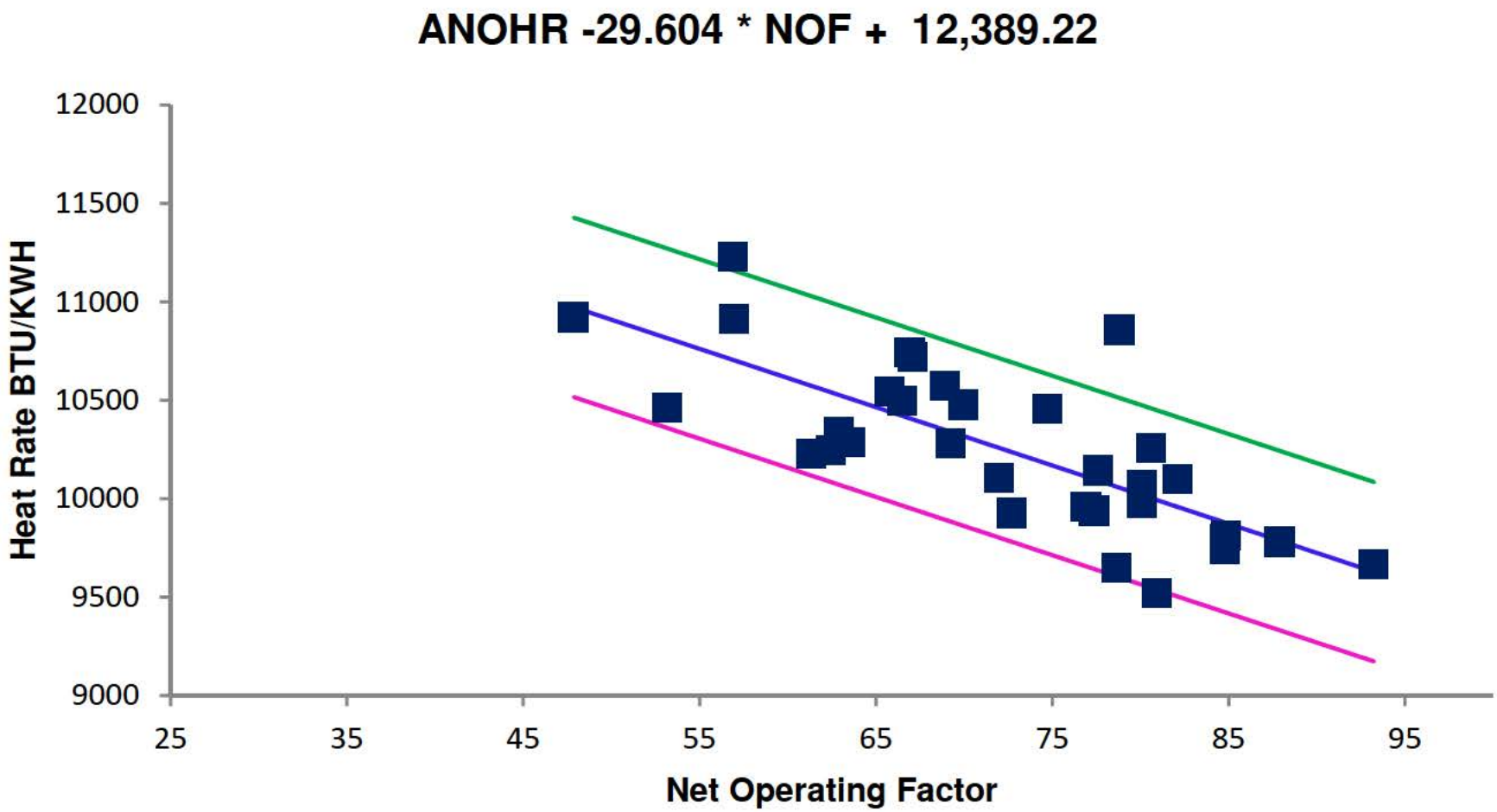
ANOHR -29.604 * NOF + 12,389.22

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-13	67.0	10,739	10,407	332.5	455.6
Aug-13	70.0	10,475	10,318	157.4	455.6
Sep-13	66.5	10,494	10,419	74.5	455.6
Oct-13	63.6	10,283	10,506	-223.5	455.6
Nov-13	62.9	10,334	10,527	-192.4	455.6
Jan-14	87.9	9,778	9,786	-8.4	455.6
Feb-14	93.2	9,665	9,629	36.0	455.6
Mar-14	77.4	9,937	10,098	-161.2	455.6
Apr-14	84.9	9,810	9,877	-67.3	455.6
May-14	84.8	9,740	9,879	-138.7	455.6
Jun-14	78.8	10,854	10,055	799.3	455.6
Jul-14	81.0	9,517	9,992	-475.0	455.6
Aug-14	82.1	10,097	9,958	139.3	455.6
Sep-14	74.7	10,456	10,177	278.3	455.6
Oct-14	72.7	9,923	10,236	-312.9	455.6
Nov-14	78.7	9,649	10,060	-411.4	455.6
Dec-14	84.8	9,795	9,879	-84.4	455.6
Jan-15	80.6	10,253	10,003	250.2	455.6
Feb-15	69.2	10,281	10,339	-57.8	455.6
Mar-15	80.1	9,977	10,017	-40.3	455.6
Apr-15	80.1	10,066	10,018	47.6	455.6
May-15	76.9	9,954	10,112	-157.3	455.6
Jun-15	72.0	10,100	10,258	-158.8	455.6
Jul-15	68.9	10,571	10,349	222.5	455.6
Aug-15	67.1	10,718	10,403	315.9	455.6
Sep-15	65.8	10,541	10,441	100.0	455.6
Oct-15	62.5	10,245	10,539	-294.4	455.6
Jan-16	56.9	11,230	10,705	524.9	455.6
Feb-16	47.9	10,921	10,972	-51.4	455.6
Mar-16	53.2	10,460	10,814	-354.0	455.6
Apr-16	61.4	10,224	10,573	-348.5	455.6
May-16	57.0	10,912	10,702	210.8	455.6
Jun-16	77.6	10,140	10,091	48.7	455.6

Regression Output:

Constant	12389.22
Std Err of Y Est	281.2508949
R Squared	0.566010252
No. of Observations	33
Degrees of Freedom	31
X Coefficient	-29.6037347
Std Err of Coef.	4.655788496


ANOHR -29.604 * NOF + 12,389.22
Heat Rate BTU/KWH
12000
11500
11000
10500
10000
9500
9000
25
35
45
55
65
75
85
95
Net Operating Factor

DUKE ENERGY FLORIDA

Hines Unit 1

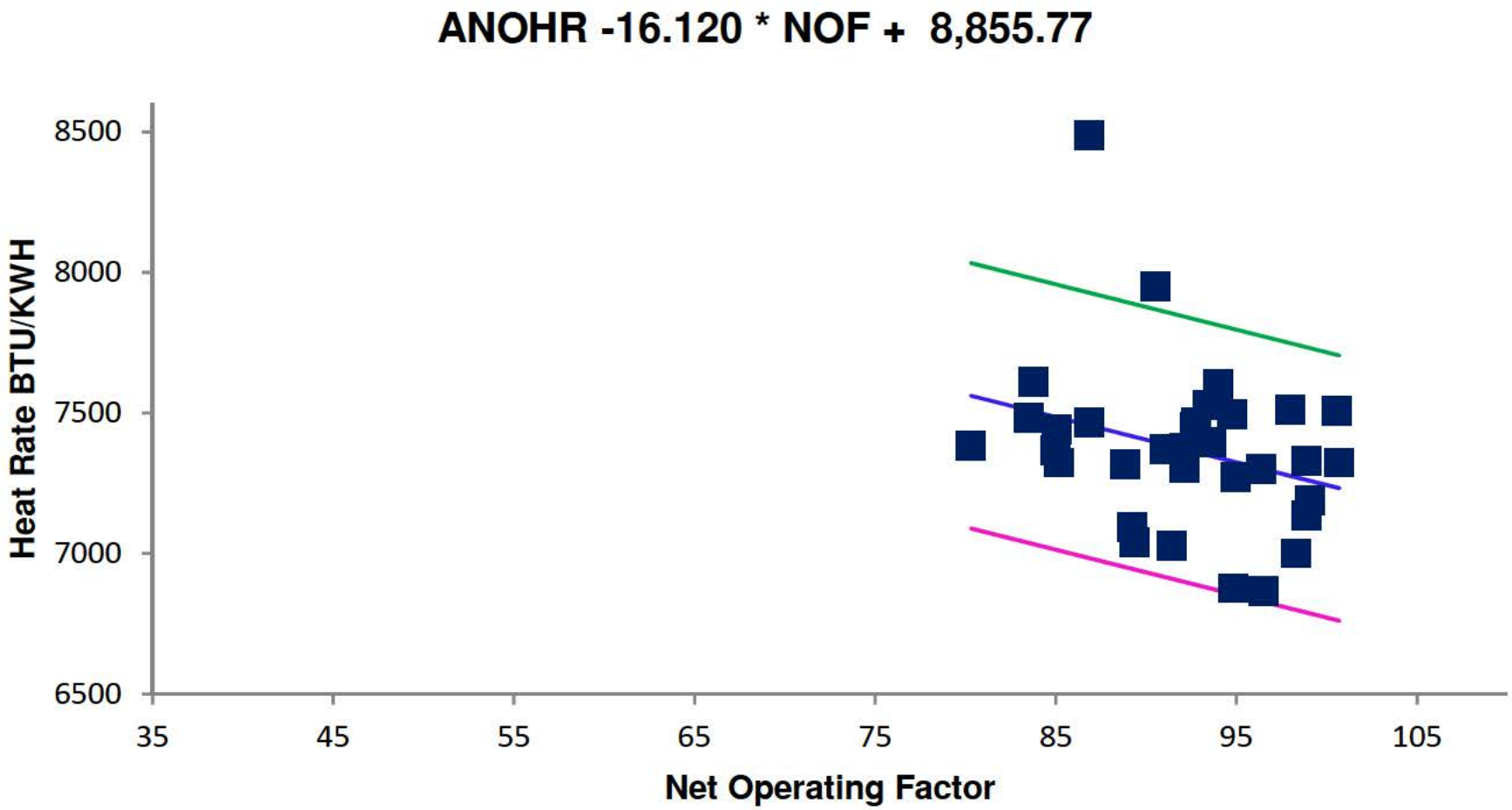
ANOHR -16.120 * NOF + 8,855.77

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-13	85.2	7,322	7,482	-159.8	472.0
Aug-13	92.8	7,464	7,360	104.4	472.0
Sep-13	92.2	7,304	7,370	-65.5	472.0
Oct-13	99.1	7,189	7,258	-69.2	472.0
Nov-13	85.0	7,364	7,486	-122.2	472.0
Jan-14	98.4	6,999	7,270	-270.7	472.0
Feb-14	93.7	7,395	7,346	48.7	472.0
Mar-14	98.9	7,132	7,261	-129.4	472.0
Apr-14	86.9	8,486	7,455	1031.3	472.0
May-14	88.9	7,314	7,423	-108.9	472.0
Jun-14	85.1	7,440	7,484	-43.8	472.0
Jul-14	94.0	7,601	7,340	260.7	472.0
Aug-14	98.0	7,511	7,276	234.5	472.0
Sep-14	96.5	6,863	7,300	-436.7	472.0
Oct-14	91.5	7,026	7,381	-355.7	472.0
Nov-14	100.6	7,507	7,234	273.0	472.0
Dec-14	100.7	7,321	7,233	88.4	472.0
Jan-15	86.9	7,463	7,455	8.4	472.0
Feb-15	91.0	7,368	7,388	-20.1	472.0
Apr-15	96.4	7,298	7,302	-3.3	472.0
May-15	94.8	6,875	7,327	-452.4	472.0
Jun-15	93.4	7,528	7,350	178.0	472.0
Jul-15	94.8	7,493	7,328	165.2	472.0
Aug-15	92.2	7,372	7,370	1.9	472.0
Sep-15	95.0	7,271	7,324	-53.0	472.0
Oct-15	98.9	7,327	7,261	66.4	472.0
Nov-15	92.7	7,449	7,361	87.9	472.0
Dec-15	90.6	7,949	7,396	553.7	472.0
Jan-16	89.3	7,090	7,417	-327.1	472.0
Feb-16	89.4	7,038	7,415	-377.1	472.0
Mar-16	83.8	7,608	7,505	103.2	472.0
May-16	80.3	7,380	7,561	-181.5	472.0
Jun-16	83.6	7,479	7,509	-29.5	472.0

Regression Output:

Constant	8855.77
Std Err of Y Est	291.3822404
R Squared	0.085398836
No. of Observations	33
Degrees of Freedom	31
X Coefficient	-16.12030318
Std Err of Coef.	9.475066289


ANOHR -16.120 * NOF + 8,855.77
Heat Rate BTU/KWH
8500
8000
7500
7000
6500
35
45
55
65
75
85
95
105
Net Operating Factor

DUKE ENERGY FLORIDA

Hines Unit 2

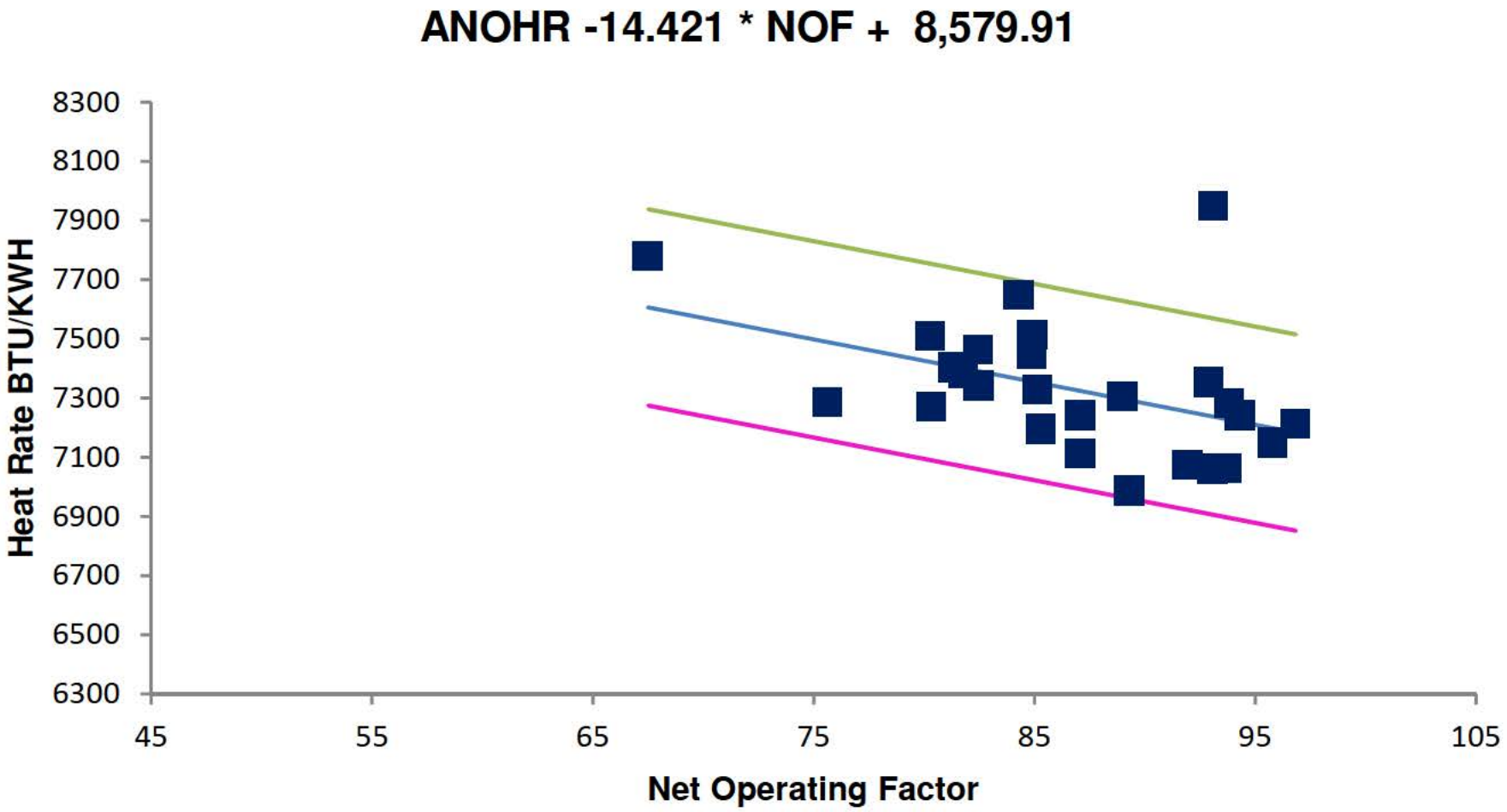
ANOHR -14.421 * NOF + 8,579.91

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-13	85.2	7,327	7,352	-25.0	331.6
Aug-13	92.0	7,072	7,254	-181.7	331.6
Sep-13	93.8	7,280	7,227	52.8	331.6
Oct-13	94.3	7,241	7,220	21.5	331.6
Nov-13	75.6	7,283	7,489	-205.6	331.6
Dec-13	81.8	7,380	7,400	-20.2	331.6
Jan-14	84.3	7,649	7,364	284.5	331.6
Feb-14	67.5	7,778	7,606	171.3	331.6
Mar-14	84.9	7,449	7,356	93.1	331.6
Apr-14	89.0	7,303	7,297	6.7	331.6
May-14	84.9	7,512	7,355	156.7	331.6
Jun-14	82.5	7,462	7,391	71.5	331.6
Jul-14	82.5	7,340	7,390	-50.2	331.6
Jun-15	93.1	7,948	7,237	711.1	331.6
Jul-15	95.8	7,147	7,199	-51.2	331.6
Aug-15	93.7	7,061	7,229	-167.2	331.6
Sep-15	89.3	6,985	7,292	-307.5	331.6
Oct-15	96.8	7,212	7,183	28.4	331.6
Nov-15	93.1	7,059	7,237	-178.1	331.6
Dec-15	92.9	7,352	7,240	111.9	331.6
Jan-16	81.3	7,402	7,407	-5.3	331.6
Feb-16	80.3	7,509	7,422	87.0	331.6
Mar-16	80.4	7,270	7,421	-151.6	331.6
Apr-16	87.1	7,241	7,324	-83.3	331.6
May-16	85.3	7,193	7,350	-156.2	331.6
Jun-16	87.1	7,111	7,324	-213.4	331.6

Regression Output:

Constant	8579.91
Std Err of Y Est	205.5503206
R Squared	0.195052172
No. of Observations	26
Degrees of Freedom	24
X Coefficient	-14.42104432
Std Err of Coef.	5.979977656


ANOHR -14.421 * NOF + 8,579.91
Heat Rate BTU/KWH
8300
8100
7900
7700
7500
7300
7100
6900
6700
6500
6300
45
55
65
75
85
95
105
Net Operating Factor

DUKE ENERGY FLORIDA

Hines Unit 3

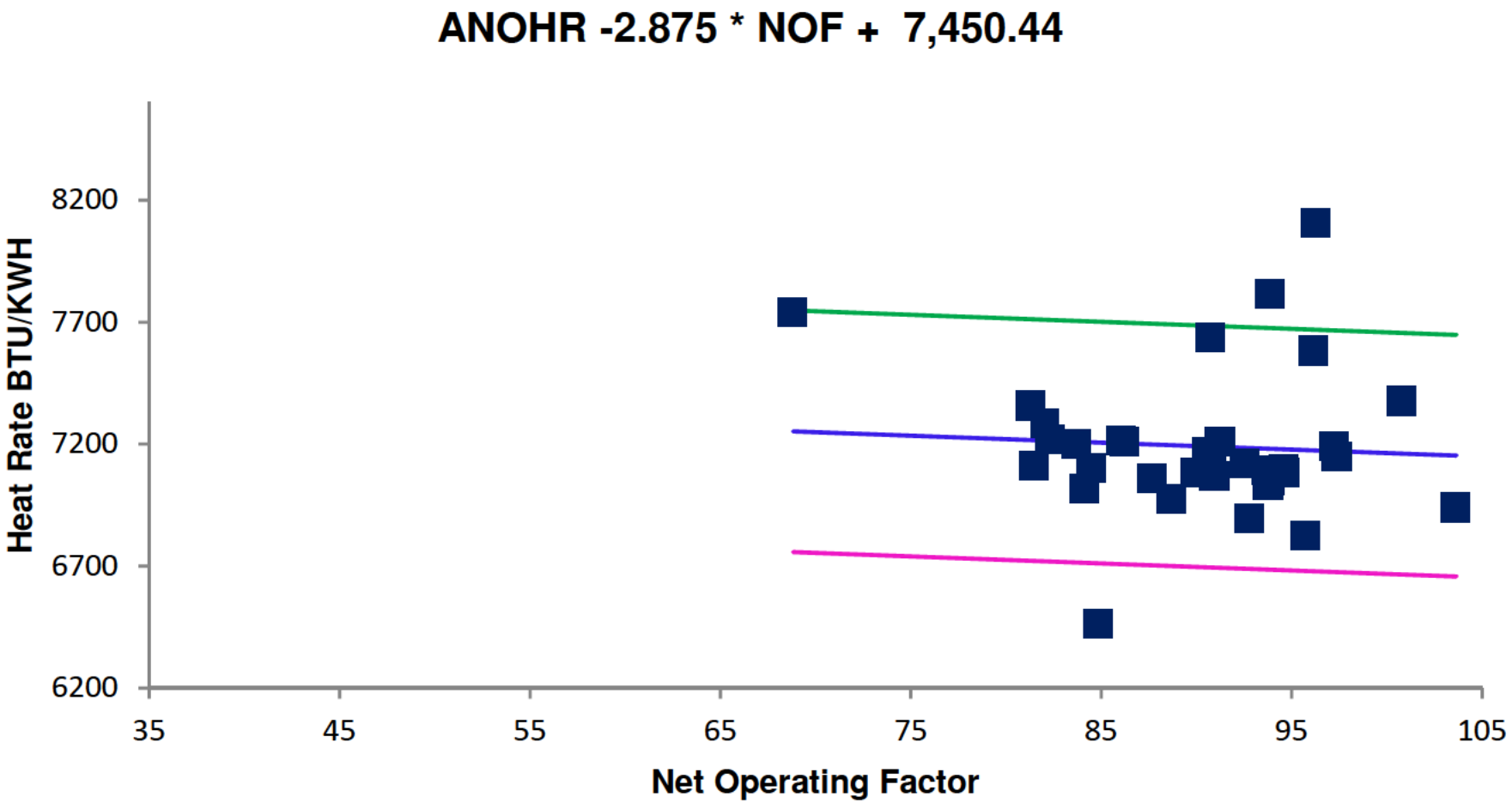
ANOHR -2.875 * NOF + 7,450.44

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-13	86.3	7,208	7,202	5.9	495.1
Aug-13	90.8	7,089	7,189	-100.3	495.1
Sep-13	92.6	7,118	7,184	-66.0	495.1
Oct-13	94.6	7,095	7,178	-83.2	495.1
Nov-13	81.5	7,111	7,216	-105.1	495.1
Dec-13	84.1	7,015	7,209	-193.3	495.1
Jan-14	91.3	7,208	7,188	20.4	495.1
Feb-14	68.8	7,739	7,253	486.0	495.1
Apr-14	90.0	7,082	7,192	-109.4	495.1
May-14	84.8	6,463	7,207	-743.5	495.1
Jun-14	90.5	7,164	7,190	-25.8	495.1
Jul-14	93.8	7,028	7,181	-152.9	495.1
Aug-14	95.7	6,823	7,175	-352.5	495.1
Sep-14	96.3	8,107	7,174	933.1	495.1
Oct-14	96.2	7,580	7,174	406.5	495.1
Nov-14	103.6	6,938	7,152	-214.4	495.1
Dec-14	100.8	7,374	7,161	213.5	495.1
Jan-15	84.5	7,101	7,208	-107.0	495.1
Feb-15	88.7	6,971	7,195	-224.1	495.1
Mar-15	87.7	7,059	7,198	-138.8	495.1
Apr-15	97.4	7,147	7,170	-23.2	495.1
May-15	90.7	7,635	7,190	445.9	495.1
Jun-15	93.7	7,092	7,181	-89.4	495.1
Jul-15	94.6	7,082	7,178	-96.3	495.1
Aug-15	93.9	7,046	7,181	-134.4	495.1
Sep-15	93.9	7,813	7,181	632.0	495.1
Oct-15	97.2	7,187	7,171	16.3	495.1
Nov-15	92.8	6,893	7,184	-290.9	495.1
Dec-15	91.0	7,068	7,189	-121.2	495.1
Jan-16	86.1	7,213	7,203	10.4	495.1
Feb-16	82.1	7,285	7,215	70.2	495.1
Mar-16	82.4	7,218	7,214	4.7	495.1
Apr-16	83.7	7,198	7,210	-11.7	495.1
Jun-16	81.3	7,355	7,217	138.4	495.1

Regression Output:

Constant	7450.44
Std Err of Y Est	305.4683318
R Squared	0.004202495
No. of Observations	34
Degrees of Freedom	32
X Coefficient	-2.875199172
Std Err of Coef.	7.823928616


ANOHR -2.875 * NOF + 7,450.44
Heat Rate BTU/KWH
8200
7700
7200
6700
6200
35
45
55
65
75
85
95
105
Net Operating Factor

DUKE ENERGY FLORIDA

Hines Unit 4

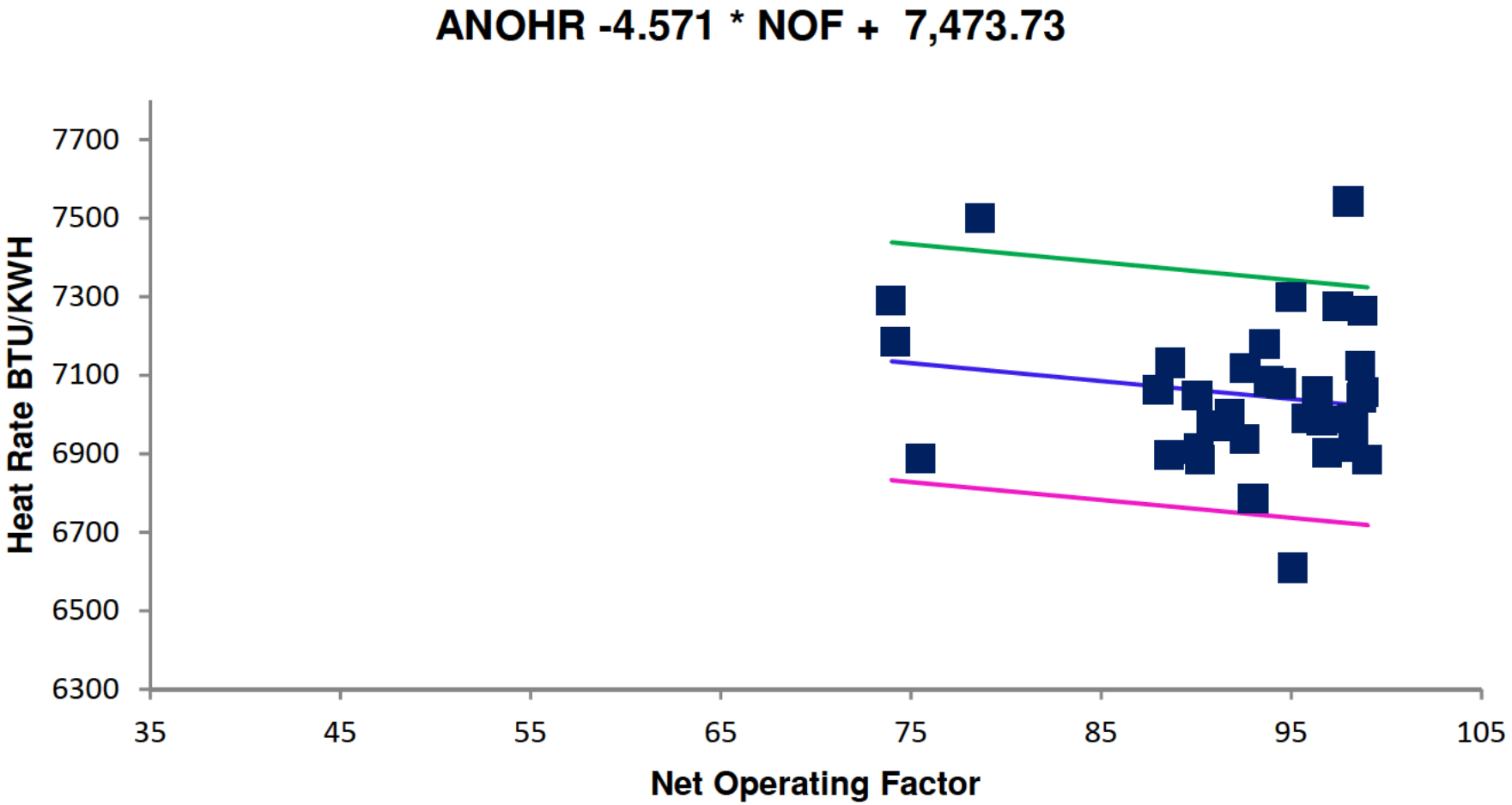
ANOHR -4.571 * NOF + 7,473.73

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-13	98.7	7,041	7,023	18.2	302.9
Aug-13	97.5	7,275	7,028	246.8	302.9
Sep-13	94.5	7,078	7,042	36.1	302.9
Oct-13	95.0	7,298	7,039	258.7	302.9
Nov-13	98.3	6,980	7,024	-44.1	302.9
Dec-13	96.9	6,902	7,031	-129.3	302.9
Jan-14	92.6	7,117	7,050	66.3	302.9
Feb-14	88.7	7,129	7,068	61.0	302.9
Mar-14	99.0	6,884	7,021	-136.9	302.9
Apr-14	95.9	6,989	7,035	-46.6	302.9
May-14	96.4	7,057	7,033	24.0	302.9
Jun-14	93.8	7,083	7,045	38.4	302.9
Jul-14	98.3	6,916	7,024	-108.8	302.9
Aug-14	98.8	7,264	7,022	241.4	302.9
Sep-14	95.1	6,608	7,039	-430.8	302.9
Oct-14	88.0	7,062	7,071	-9.1	302.9
Nov-14	74.0	7,288	7,136	152.2	302.9
Dec-14	90.2	6,882	7,061	-178.9	302.9
Jan-15	90.2	6,911	7,062	-150.2	302.9
Feb-15	88.6	6,895	7,069	-174.2	302.9
Mar-15	90.8	6,972	7,059	-87.0	302.9
Apr-15	98.7	7,123	7,023	100.6	302.9
May-15	98.0	7,541	7,026	515.4	302.9
Jun-15	93.6	7,178	7,046	132.7	302.9
Jul-15	98.8	7,055	7,022	33.3	302.9
Aug-15	98.3	6,988	7,025	-36.5	302.9
Sep-15	96.7	6,982	7,032	-49.8	302.9
Oct-15	78.7	7,498	7,114	384.2	302.9
Nov-15	75.6	6,885	7,128	-242.9	302.9
Dec-15	93.0	6,784	7,048	-264.9	302.9
Jan-16	92.5	6,937	7,051	-114.0	302.9
Feb-16	91.8	7,001	7,054	-53.4	302.9
Mar-16	91.5	6,969	7,056	-86.7	302.9
Apr-16	90.1	7,047	7,062	-14.5	302.9
May-16	74.2	7,184	7,134	49.3	302.9

Regression Output:

Constant	7473.73
Std Err of Y Est	186.8109816
R Squared	0.029290181
No. of Observations	35
Degrees of Freedom	33
X Coefficient	-4.570977472
Std Err of Coef.	4.580741598


ANOHR -4.571 * NOF + 7,473.73
Heat Rate BTU/KWH
7700
7500
7300
7100
6900
6700
6500
6300
35
45
55
65
75
85
95
105
Net Operating Factor

UNPLANNED OUTAGE RATE TABLES AND GRAPHS

Bartow
Unit 4

	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
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	696.68	744 00	670.11	702.64	673.06	699.77	742.17	660.09	647.94	358.53	306 68	671.92	744.00	734.05	709.77	729.45	449.39	285.41
RSH	14.37	0 00	36.90	41.36	47.62	17.41	0.83	2.53	21.58	0.00	0 00	0.62	0.00	0.00	0.00	9.48	48.56	96.44
UH	32.95	0 00	12.99	0.00	0.32	26.82	1.00	9.38	73.48	361.47	437 32	47.46	0.00	9.95	10.23	5.07	223.05	362.15
POH	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	19 61	218.31	61 84	0.00	0.00	0.00	0.00	0.00	216.73	360 37
FOH	4.29	0 00	6.15	0.00	0.32	26.82	1.00	9.38	1 08	143.17	375.49	40.87	0.00	7.04	4.74	5.07	0.00	1.78
MOH	28.66	0 00	6.84	0.00	0.00	0.00	0.00	0.00	52.79	0.00	0 00	6.59	0.00	2.91	5.48	0.00	6.32	0 00
PFOH	10.47	45.75	60.31	0.00	0.71	58.53	2.22	20.76	2.40	0.00	0 00	1.32	5.33	15.36	52.84	12.31	0.00	0 00
LRPF	69.31	16.19	77.82	0.00	69.63	69.50	109.65	98.02	198.57	0.00	0 00	54.76	156.80	109.50	44.08	107.66	0.00	0 00
EFOH	0.68	0 69	4.37	0.00	0.05	3.79	0.23	1.89	0.44	0.00	0 00	0.07	0.78	1.57	2.17	1.23	0.00	0 00
PMOH	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	110 81	0.00	0 00	14.55	0.00	6.47	12.15	0.00	0.00	0 00
LRPM	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	109.50	0.00	0 00	109.52	0.00	109.56	109.47	0.00	0.00	0 00
EMOH	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	11 30	0.00	0 00	1.48	0.00	0.66	1.24	0.00	0.00	0 00
NPC	1074.00	1074 00	1074.00	1074.00	1074.00	1074.00	1074.00	1074.00	1074 00	1074.00	1074 00	1074.00	1074.00	1074.00	1074.00	1074.00	1074.00	1074 00

MONTHLY	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
FOR	0.61	0 00	0.91	0.00	0.05	3.69	0.13	1.40	0.17	28.54	55 04	5.73	0.00	0.95	0.66	0.69	0.00	0 62
MOR	3.95	0 00	1.01	0.00	0.00	0.00	0.00	0.00	7.53	0.00	0 00	0.97	0.00	0.39	0.77	0.00	1.39	0 00
PFOR	0.10	0 09	0.65	0.00	0.01	0.54	0.03	0.29	0 07	0.00	0 00	0.01	0.10	0.21	0.31	0.17	0.00	0 00
PMOR	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	1.74	0.00	0 00	0.22	0.00	0.09	0.17	0.00	0.00	0 00
EUOR	4.61	0 09	2.54	0.00	0.05	4.21	0.17	1.68	9 35	28.54	55 04	6.81	0.10	1.64	1.89	0.86	1.39	0 62
EUOF	4.52	0 09	2.41	0.00	0.05	4.11	0.16	1.68	8 83	19.88	50.47	6.81	0.10	1.64	1.89	0.85	0.88	0 24
POF	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	2 64	30.32	8 31	0.00	0.00	0.00	0.00	0.00	30.06	48.44
EAF	95.48	99.91	97.59	100.00	99.95	95.89	99.84	98.32	88.53	49.79	41 22	93.19	99.90	98.36	98.11	99.15	69.06	51 32

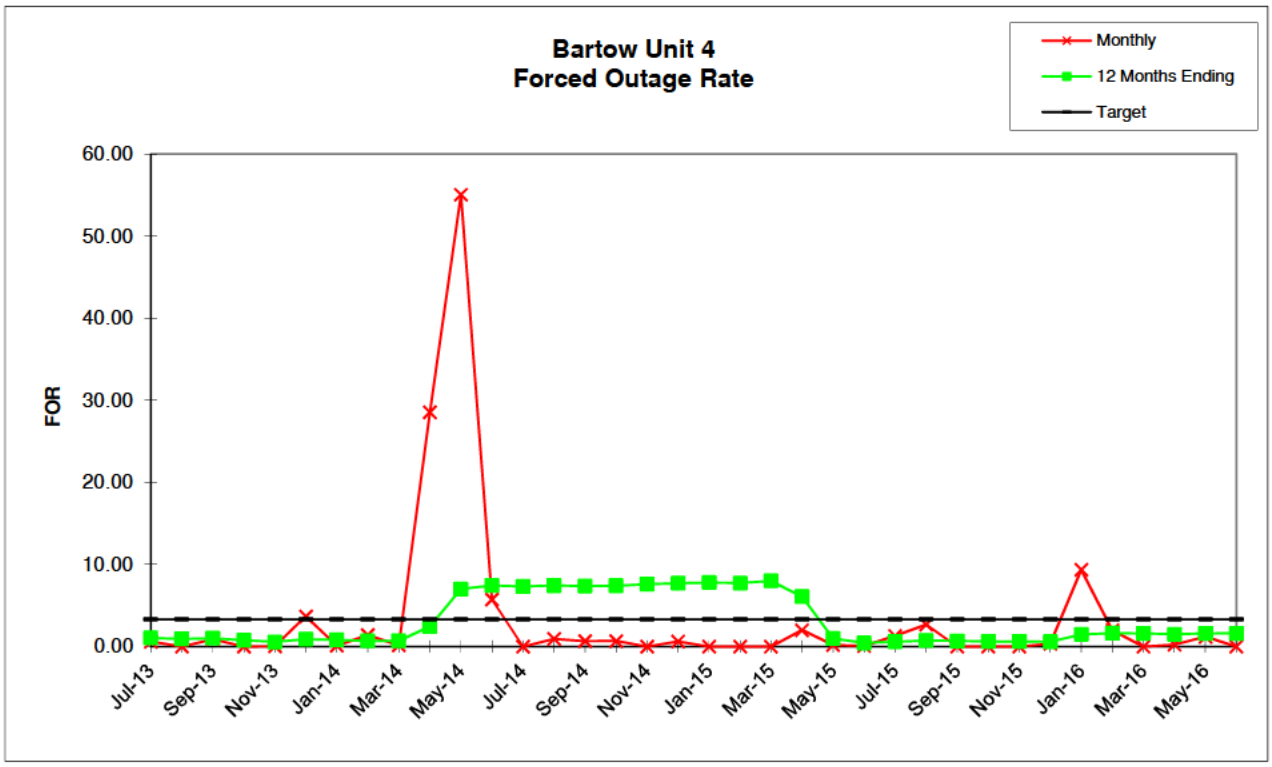
12 MONTHS	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
FOR	1.05	0.95	1.03	0.80	0.57	0.91	0.81	0.71	0.70	2.46	7 00	7.44	7.35	7.43	7.38	7.42	7.62	7.73
MOR	1.48	1.48	1.23	1.12	1.11	1.10	1.01	0.99	1.59	1.44	1.17	1.24	0.86	0.90	0.88	0.87	0.98	1 04
PFOR	0.85	0 80	0.82	0.69	0.65	0.65	0.62	0.64	0.56	0.17	0.17	0.16	0.16	0.17	0.14	0.16	0.16	0.12
PMOR	0.14	0.13	0.09	0.09	0.09	0.07	0.07	0.07	0 21	0.21	0.15	0.17	0.17	0.18	0.19	0.19	0.20	0 21
EUOR	3.46	3 32	3.13	2.67	2.40	2.71	2.49	2.38	3 02	4.21	8 32	8.80	8.39	8.53	8.45	8.49	8.79	8.92
EUOF	3.08	2.95	2.78	2.35	2.13	2.43	2.27	2.20	2 89	3.96	7 84	8.32	7.94	8.07	8.03	8.10	8.17	7 84
POF	5.78	5.78	5.78	5.78	4.62	4.62	4.62	3.62	0 22	2.72	3.42	3.42	3.42	3.42	3.42	3.42	5.90	10 01
EAF	91.15	91 28	91.45	91.87	93.25	92.95	93.11	94.17	96 88	93.32	88.74	88.26	88.64	88.51	88.55	88.48	85.94	82.15

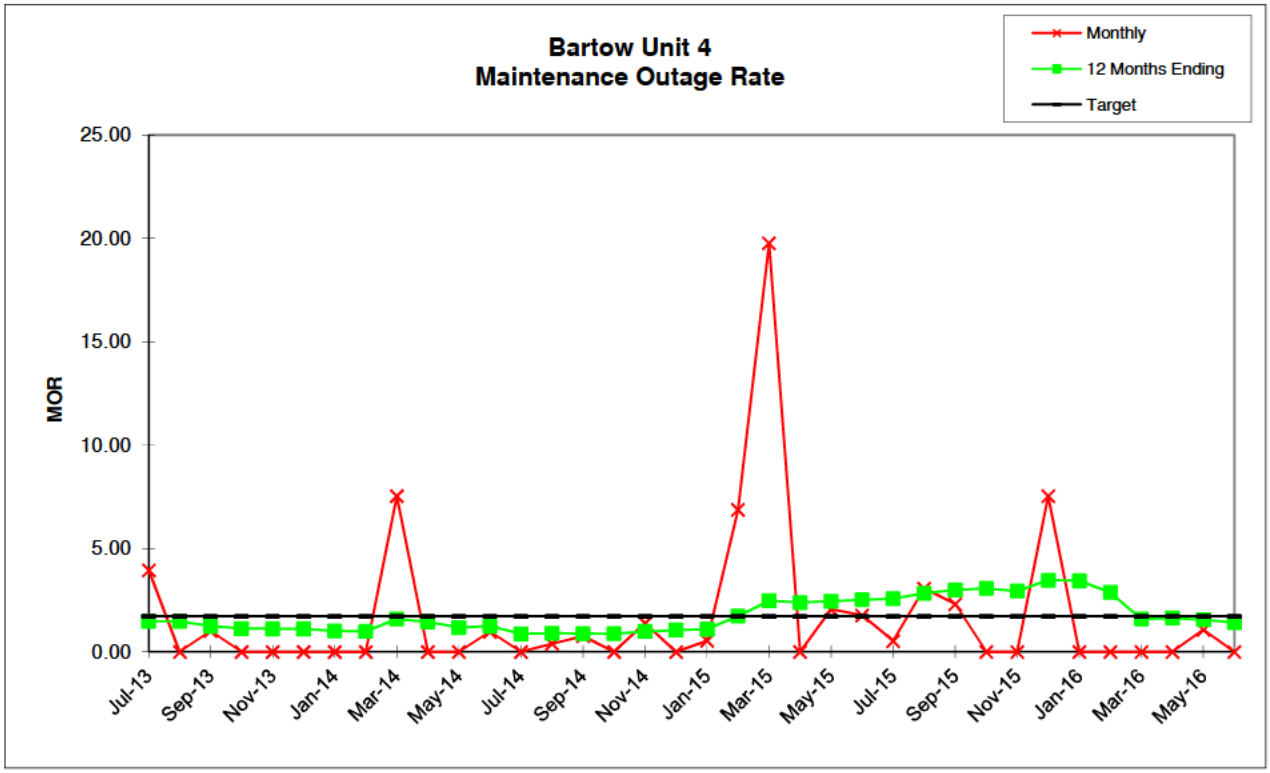
Bartow
Unit 4

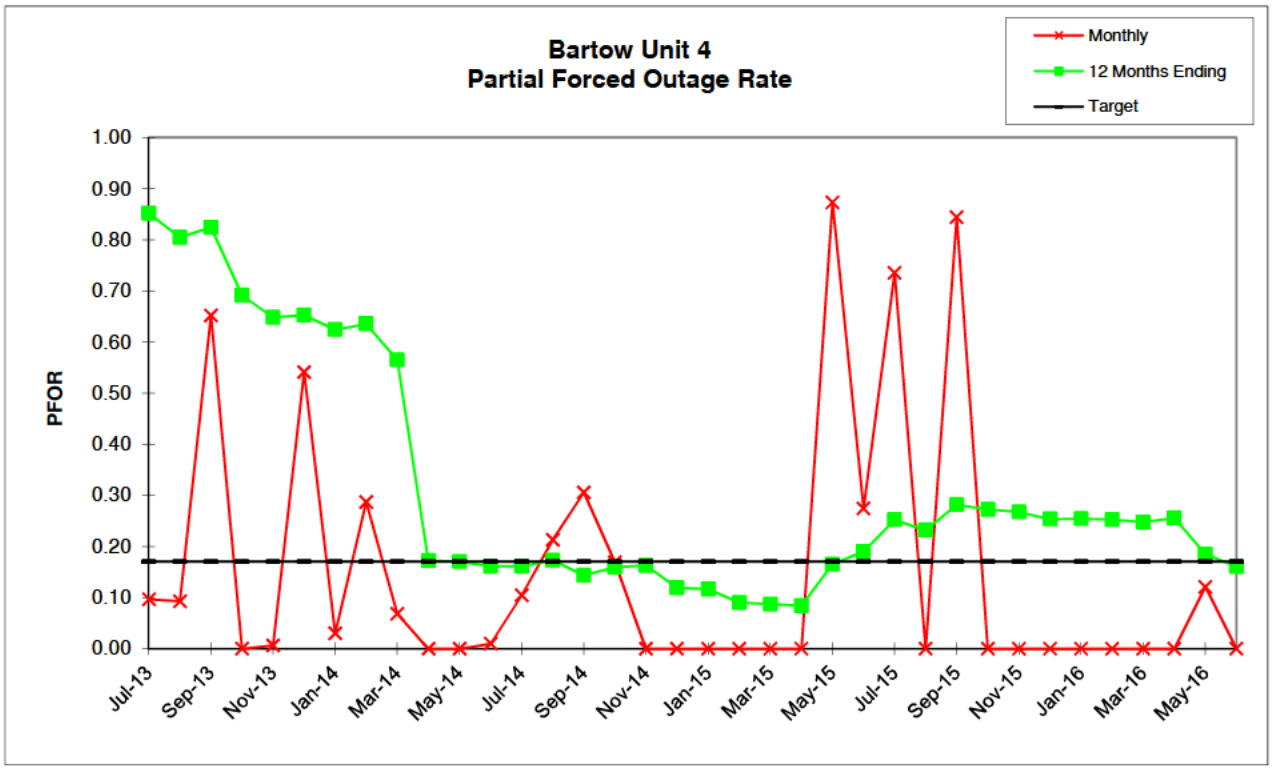
	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
PER HOURS	744.00	672 00	743.00	720.00	744.00	720.00	744.00	744.00	720 00	744.00	721 00	744.00	744.00	696.00	743.00	720.00	744.00	720 00
SER HOURS	669.89	591.55	406.16	614.52	726.67	692.25	716.81	690.70	670.45	516.38	585.59	680.70	648.71	645.84	548.91	378.51	440.49	612.16
RSH	12.21	36 36	13.99	12.02	0.55	14.65	13.83	12.27	15.47	9.75	14.49	5.32	28.26	36.95	23.14	0.00	4.59	0 00
UH	61.90	44 09	322.85	93.46	16.78	13.10	13.36	41.03	34 08	217.87	120.92	57.98	67.03	13.21	170.95	341.49	298.92	107 84
POH	58.32	0.45	222.76	80.85	0.00	0.00	0.00	0.00	18 24	217.87	120.92	0.00	0.00	0.00	170.95	340.57	288.85	107 84
FOH	0.00	0 00	0.00	12.61	1.53	0.65	9.56	19.19	0 00	0.00	0 00	2.51	67.03	13.21	0.00	0.92	5.33	0 00
MOH	3.58	43 65	100.09	0.00	15.25	12.45	3.80	21.84	15 84	0.00	0 00	55.47	0.00	0.00	0.00	0.00	4.74	0 00
PFOH	0.00	0 00	0.00	0.00	57.29	14.87	44.44	0.00	33 85	0.00	0 00	0.00	0.00	0.00	0.00	0.00	42.97	0 00
LRPF	0.00	0 00	0.00	0.00	119.12	137.56	137.54	0.00	193.99	0.00	0 00	0.00	0.00	0.00	0.00	0.00	14.41	0 00
EFOH	0.00	0 00	0.00	0.00	6.34	1.90	5.27	0.00	5 66	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.53	0 00
PMOH	0.00	0 00	0.00	3.42	34.77	0.00	0.00	0.00	0 00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0 00
LRPM	0.00	0 00	0.00	27.04	144.51	0.00	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	0.09	4.67	0.00	0.00	0.00	0 00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0 00
NPC	1076.00	1076 00	1076.00	1076.00	1076.00	1076.00	1160.00	1160.00	1160 00	1160.00	1160 00	1160.00	1162.00	1162.00	1162.00	1162.00	1162.00	1162 00

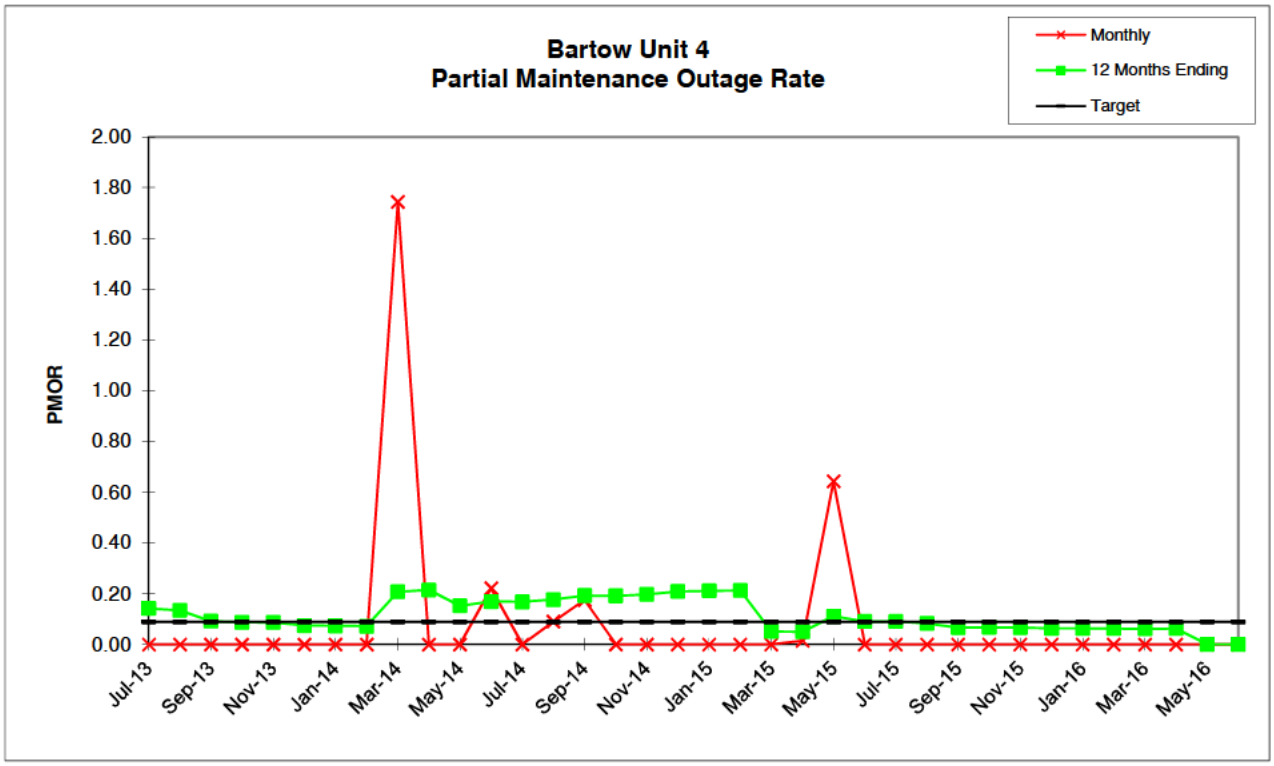
MONTHLY	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
FOR	0.00	0 00	0.00	2.01	0.21	0.09	1.32	2.70	0 00	0.00	0 00	0.37	9.37	2.00	0.00	0.24	1.20	0 00
MOR	0.53	6 87	19.77	0.00	2.06	1.77	0.53	3.07	2 31	0.00	0 00	7.53	0.00	0.00	0.00	0.00	1.06	0 00
PFOR	0.00	0 00	0.00	0.00	0.87	0.27	0.74	0.00	0 84	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.12	0 00
PMOR	0.00	0 00	0.00	0.01	0.64	0.00	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	0.53	6 87	19.77	2.02	3.74	2.13	2.55	5.61	3.13	0.00	0 00	7.85	9.37	2.00	0.00	0.24	2.35	0 00
EUOF	0.48	6.50	13.47	1.76	3.74	2.08	2.50	5.51	2.99	0.00	0 00	7.79	9.01	1.90	0.00	0.13	1.43	0 00
POF	7.84	0 07	29.98	11.23	0.00	0.00	0.00	0.00	2.53	29.28	16.77	0.00	0.00	0.00	23.01	47.30	38.82	14.98
EAF	91.68	93.44	56.55	87.01	96.26	97.92	97.50	94.49	94.48	70.72	83 23	92.21	90.99	98.10	76.99	52.57	59.75	85 02

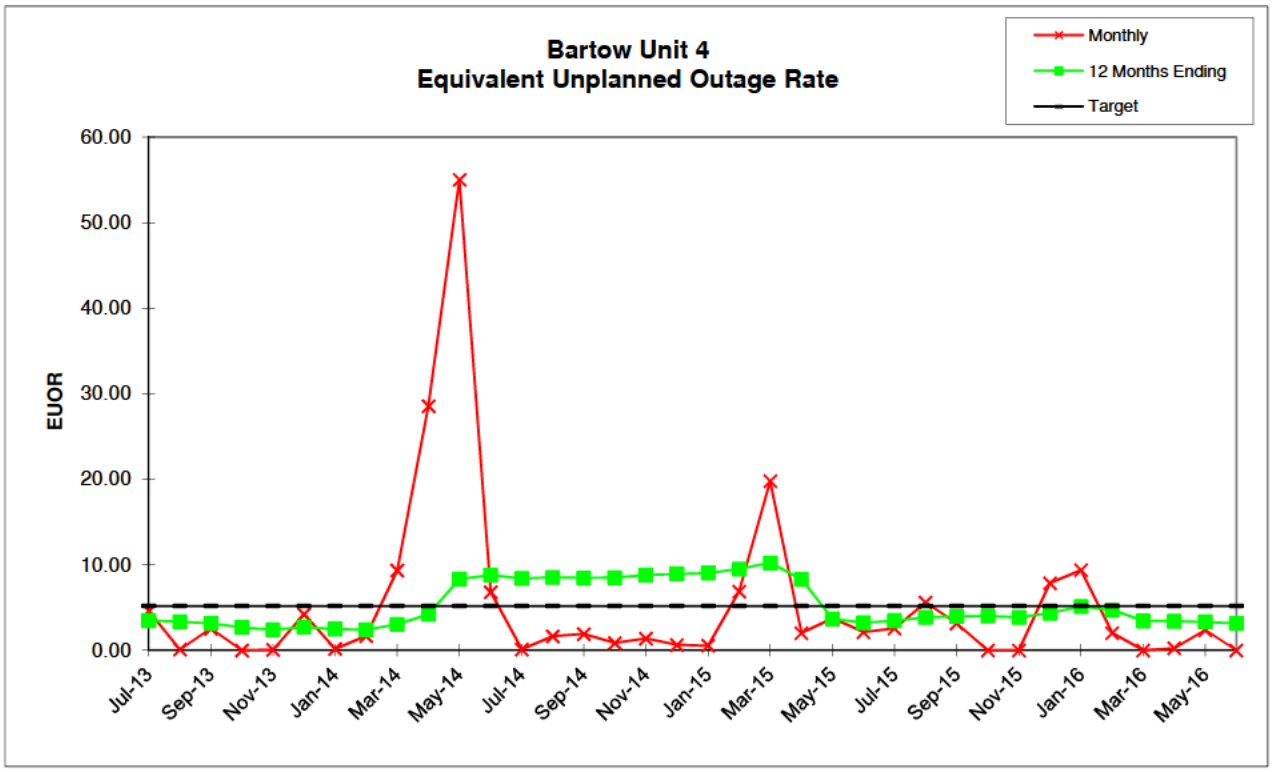
12 MONTHS	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
FOR	7.79	7.75	7.99	6.08	0.99	0.45	0.58	0.75	0 69	0.64	0 63	0.61	1.48	1.64	1.61	1.50	1.61	1 62
MOR	1.10	1.73	2.47	2.38	2.45	2.52	2.57	2.83	2.98	3.07	2.93	3.47	3.44	2.87	1.59	1.63	1.56	1.41
PFOR	0.12	0 09	0.09	0.08	0.17	0.19	0.25	0.23	0 28	0.27	0 27	0.25	0.25	0.25	0.25	0.26	0.19	0.16
PMOR	0.21	0 21	0.05	0.05	0.11	0.09	0.09	0.08	0 07	0.07	0 07	0.06	0.06	0.06	0.06	0.06	0.00	0 00
EUOR	9.03	9.49	10.21	8.31	3.66	3.22	3.46	3.85	3.97	4.00	3 85	4.34	5.12	4.72	3.44	3.40	3.30	3.14
EUOF	7.87	8 24	8.63	7.14	3.17	2.78	2.99	3.32	3.41	3.33	3 26	3.90	4.63	4.27	3.13	3.00	2.80	2 63
POF	10.68	10 68	13.00	11.43	10.72	10.72	10.72	10.72	10.93	13.42	12 33	8.21	7.55	7.52	6.93	9.89	13.18	14.40
EAF	81.46	81 08	78.37	81.43	86.10	86.49	86.29	85.96	85 66	83.25	84.41	87.88	87.83	88.21	89.94	87.12	84.02	82.97

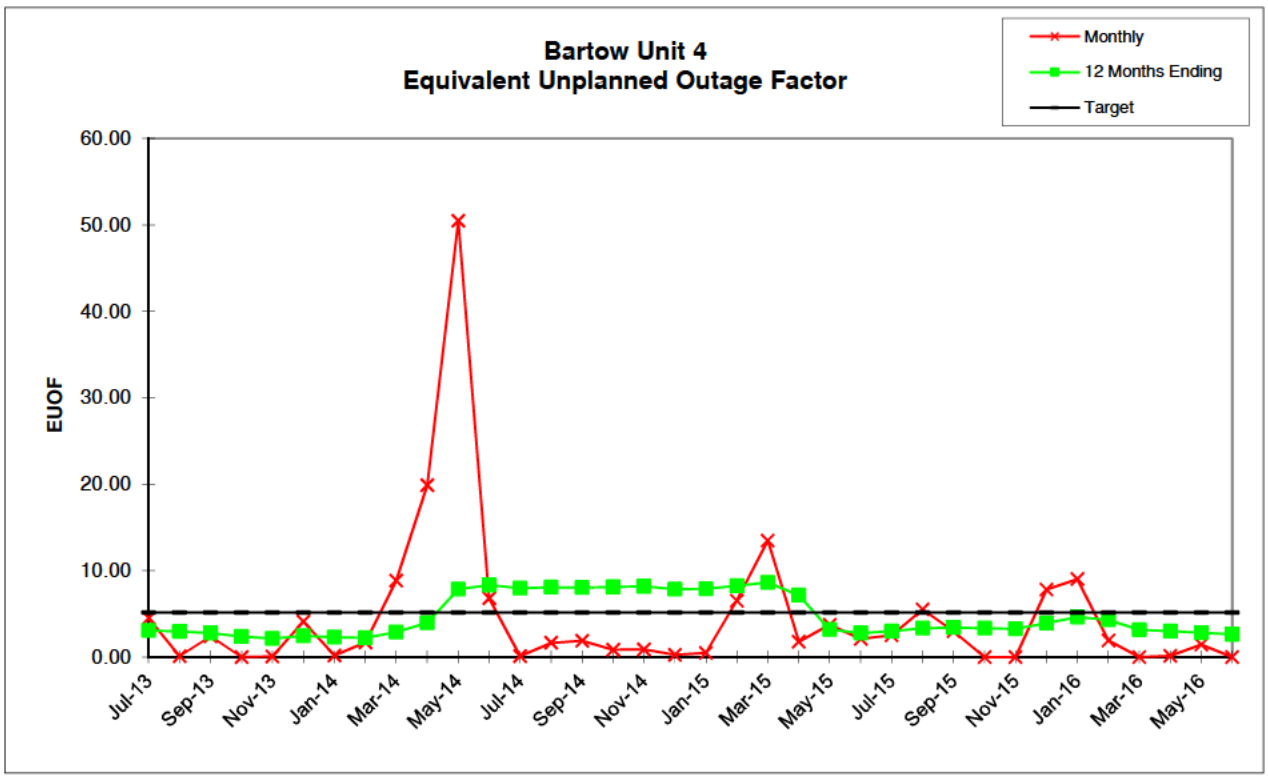

Bartow Unit 4
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Bartow Unit 4
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
25.00
20.00
15.00
10.00
5.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Bartow Unit 4
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-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Bartow Unit 4
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
2.00
1.80
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Bartow Unit 4
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Bartow Unit 4
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16

Crystal River
Unit 4

	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
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	672.00	743.00	720.00	744.00	720.00
SER HOURS	597.30	744.00	720.00	744.00	721.00	744.00	414.85	401.78	569.82	658.03	627.02	647.00	414.85	401.78	569.82	658.03	627.02	647.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	329.15	0.00	0.00	0.00	0.00	0.00	329.15	0.00	0.00	0.00	0.00	0.00
UH	146.70	0.00	0.00	0.00	0.00	0.00	0.00	270.22	173.18	61.97	116.98	73.00	0.00	270.22	173.18	61.97	116.98	73.00
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	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	270.22	57.70	61.97	0.00	73.00	0.00	270.22	57.70	61.97	0.00	73.00
MOH	146.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	115.48	0.00	116.98	0.00	0.00	0.00	115.48	0.00	116.98	0.00
PFOH	1.53	135.50	4.77	8.23	0.00	0.00	0.00	32.30	10.16	6.01	13.48	0.00	0.00	32.30	10.16	6.01	13.48	0.00
LRPF	93.20	84.00	96.74	93.04	0.00	0.00	0.00	144.39	60.65	117.13	179.04	0.00	0.00	144.39	60.65	117.13	179.04	0.00
EFOH	0.20	15.99	0.65	1.08	0.00	0.00	0.00	6.55	0.87	0.99	3.39	0.00	0.00	6.55	0.87	0.99	3.39	0.00
PMOH	0.00	35.35	15.08	34.77	217.07	5.00	59.75	12.00	7.02	0.00	0.93	0.00	59.75	12.00	7.02	0.00	0.93	0.00
LRPM	0.00	153.58	217.09	44.19	76.04	93.00	116.23	169.33	64.97	0.00	112.40	0.00	116.23	169.33	64.97	0.00	112.40	0.00
EMOH	0.00	7.63	4.60	2.16	23.18	0.65	9.75	2.85	0.64	0.00	0.15	0.00	9.75	2.85	0.64	0.00	0.15	0.00
NPC	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00

MONTHLY	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.21	9.19	8.61	0.00	10.14	0.00	40.21	9.19	8.61	0.00	10.14
MOR	19.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.85	0.00	15.72	0.00	0.00	0.00	16.85	0.00	15.72	0.00
PFOR	0.03	2.15	0.09	0.14	0.00	0.00	0.00	1.63	0.15	0.15	0.54	0.00	0.00	1.63	0.15	0.15	0.54	0.00
PMOR	0.00	1.02	0.64	0.29	3.22	0.09	2.35	0.71	0.11	0.00	0.02	0.00	2.35	0.71	0.11	0.00	0.02	0.00
EUOR	19.74	3.17	0.73	0.43	3.22	0.09	2.35	41.61	23.51	8.74	16.20	10.14	2.35	41.61	23.51	8.74	16.20	10.14
EUOF	19.74	3.17	0.73	0.43	3.22	0.09	1.31	41.61	23.51	8.74	16.20	10.14	1.31	41.61	23.51	8.74	16.20	10.14
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	0.00	0.00	0.00	0.00
EAF	80.26	96.83	99.27	99.57	96.78	99.91	98.69	58.39	76.49	91.26	83.80	89.86	98.69	58.39	76.49	91.26	83.80	89.86

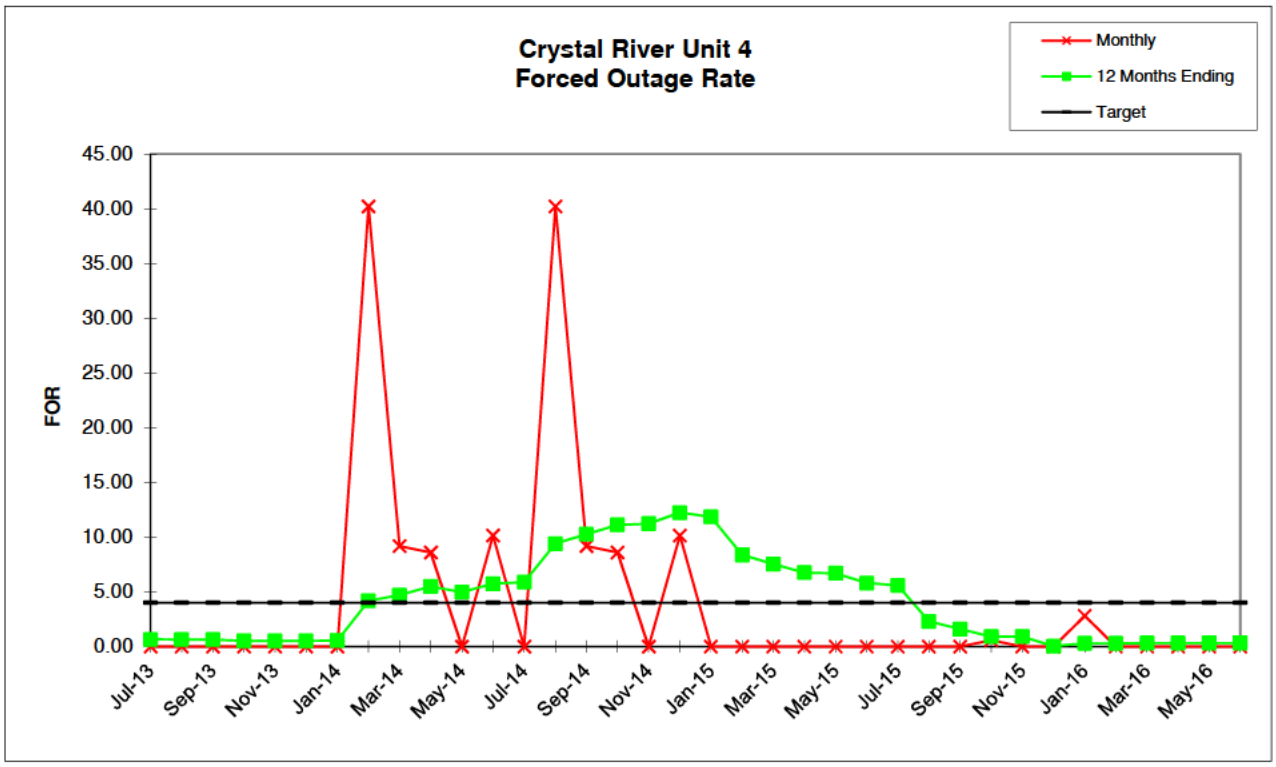
12 MONTHS	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**
FOR	0.66	0.66	0.66	0.54	0.54	0.53	0.56	4.18	4.70	5.50	4.98	5.75	5.88	9.40	10.26	11.10	11.24	12.24
MOR	8.23	7.65	7.65	7.64	7.62	6.38	6.65	6.89	7.93	7.99	7.40	4.76	3.04	3.19	4.79	4.85	6.46	6.55
PFOR	0.90	0.36	0.28	0.27	0.27	0.27	0.28	0.38	0.35	0.36	0.40	0.39	0.40	0.28	0.29	0.30	0.35	0.36
PMOR	0.83	0.81	0.60	0.43	0.58	0.58	0.73	0.78	0.75	0.70	0.69	0.68	0.83	0.80	0.76	0.74	0.41	0.40
EUOR	10.37	9.27	9.01	8.74	8.87	7.64	8.08	11.56	12.89	13.59	12.65	10.95	9.70	12.98	15.05	15.84	17.00	17.95
EUOF	9.76	8.73	8.48	8.22	8.34	7.19	7.30	10.45	12.41	13.08	12.18	10.54	8.98	12.00	13.91	14.64	15.71	16.59
POF	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	84.35	85.37	85.62	85.88	85.76	86.91	86.80	83.65	87.59	86.92	87.82	89.46	91.02	88.00	86.09	85.36	84.29	83.41

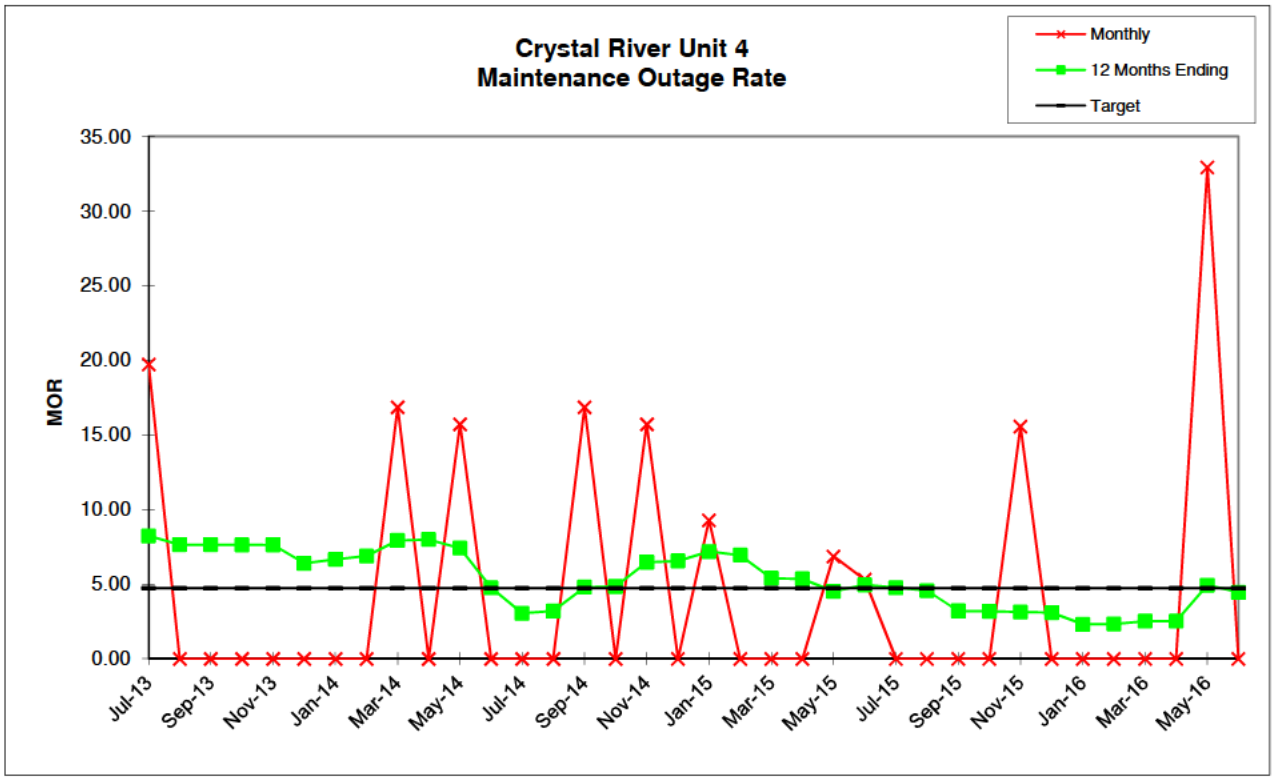
Crystal River
Unit 4

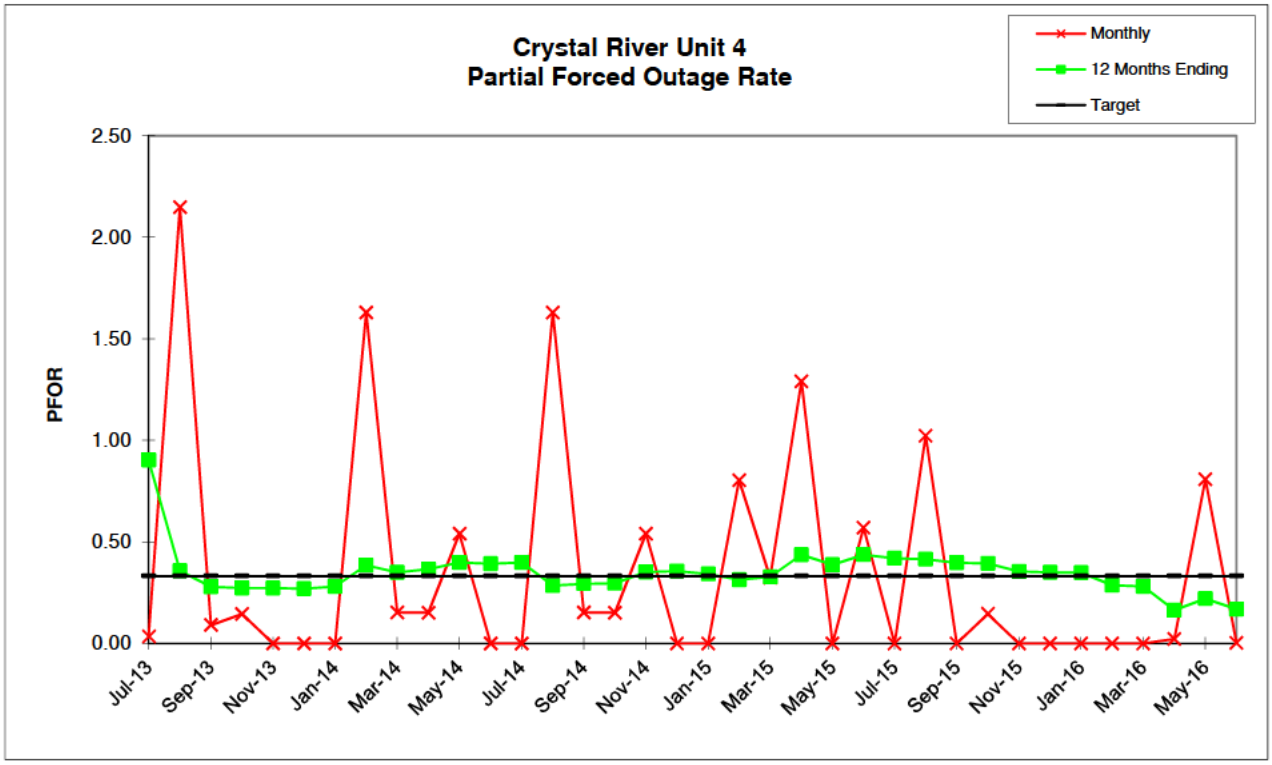
	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	696.00	743.00	720.00	744.00	720.00
SER HOURS	674.92	672.00	743.00	720.00	692.95	681.78	744.00	744.00	720.00	739.68	608.77	744.00	723.07	613.65	83.77	720.00	498.87	720.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	69.08	0.00	0.00	0.00	51.05	38.22	0.00	0.00	0.00	4.32	112.23	0.00	20.93	82.35	659.23	0.00	245.13	0.00
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	82.35	659.23	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.32	0.00	0.00	20.93	0.00	0.00	0.00	0.00	0.00
MOH	69.08	0.00	0.00	0.00	51.05	38.22	0.00	0.00	0.00	0.00	112.23	0.00	0.00	0.00	0.00	0.00	245.13	0.00
PFOH	0.00	17.42	10.25	19.68	0.00	8.25	0.00	21.42	0.00	7.08	0.00	0.00	0.00	0.00	0.00	1.17	10.10	0.25
LRPF	0.00	220.58	167.34	336.14	0.00	335.24	0.00	252.79	0.00	108.03	0.00	0.00	0.00	0.00	0.00	92.74	284.00	65.00
EFOH	0.00	5.40	2.41	9.29	0.00	3.88	0.00	7.61	0.00	1.07	0.00	0.00	0.00	0.00	0.00	0.15	4.03	0.02
PMOH	10.50	1.48	18.18	128.03	238.74	33.98	4.00	20.65	35.71	174.62	31.26	0.00	2.00	17.28	54.67	45.96	3.00	13.67
LRPM	93.00	93.21	271.95	89.18	89.61	80.63	65.00	198.85	67.41	127.94	191.25	0.00	93.00	173.96	92.99	96.52	65.00	65.62
EMOH	1.37	0.19	6.94	16.04	30.05	3.85	0.37	5.77	3.38	31.38	8.40	0.00	0.26	4.22	7.14	6.23	0.27	1.26
NPC	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00	712.00

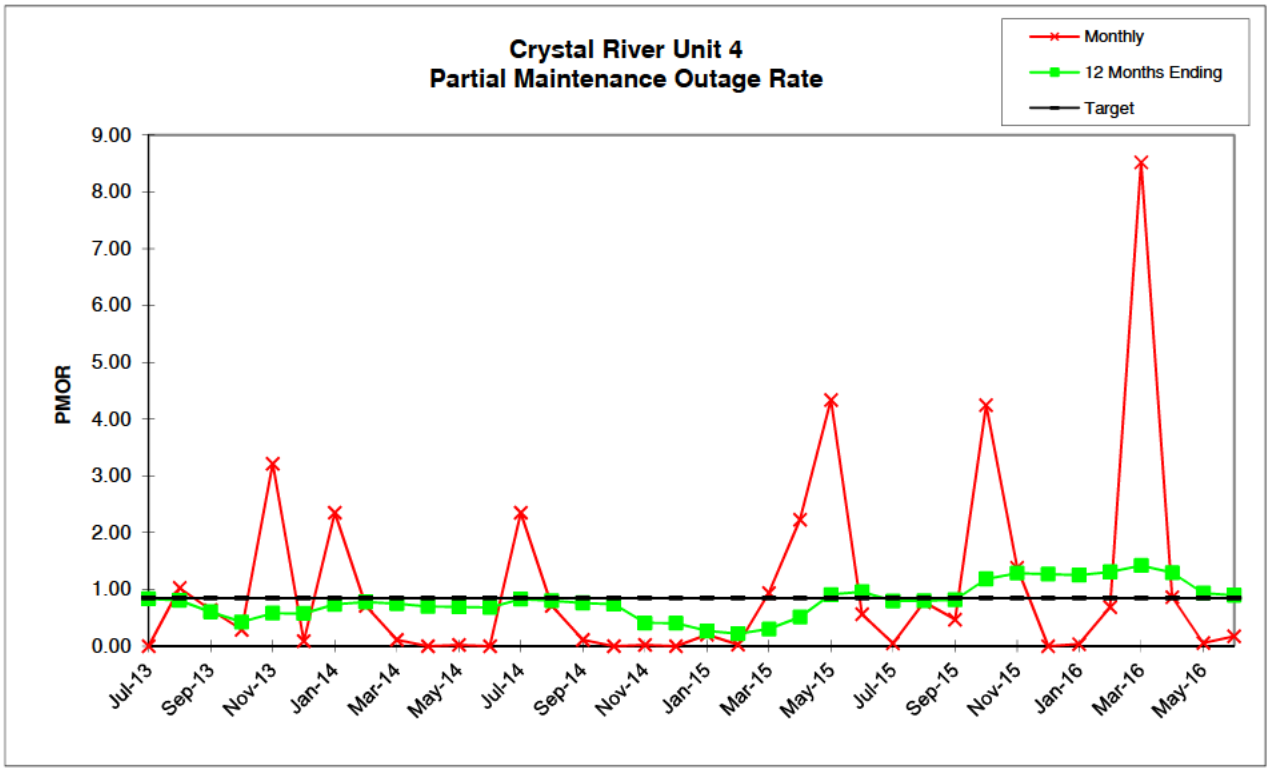
MONTHLY	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.58	0.00	0.00	2.81	0.00	0.00	0.00	0.00	0.00
MOR	9.28	0.00	0.00	0.00	6.86	5.31	0.00	0.00	0.00	0.00	15.57	0.00	0.00	0.00	0.00	0.00	32.95	0.00
PFOR	0.00	0.80	0.32	1.29	0.00	0.57	0.00	1.02	0.00	0.15	0.00	0.00	0.00	0.00	0.00	0.02	0.81	0.00
PMOR	0.20	0.03	0.93	2.23	4.34	0.56	0.05	0.78	0.47	4.24	1.38	0.00	0.04	0.69	8.52	0.87	0.05	0.17
EUOR	9.47	0.83	1.26	3.52	10.90	6.38	0.05	1.80	0.47	4.94	16.73	0.00	2.85	0.69	8.52	0.89	33.53	0.18
EUOF	9.47	0.83	1.26	3.52	10.90	6.38	0.05	1.80	0.47	4.94	16.73	0.00	2.85	0.61	0.96	0.89	33.53	0.18
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	11.83	88.73	0.00	0.00	0.00
EAF	90.53	99.17	98.74	96.48	89.10	93.62	99.95	98.20	99.53	95.06	83.27	100.00	97.15	87.56	10.31	99.11	66.47	99.82

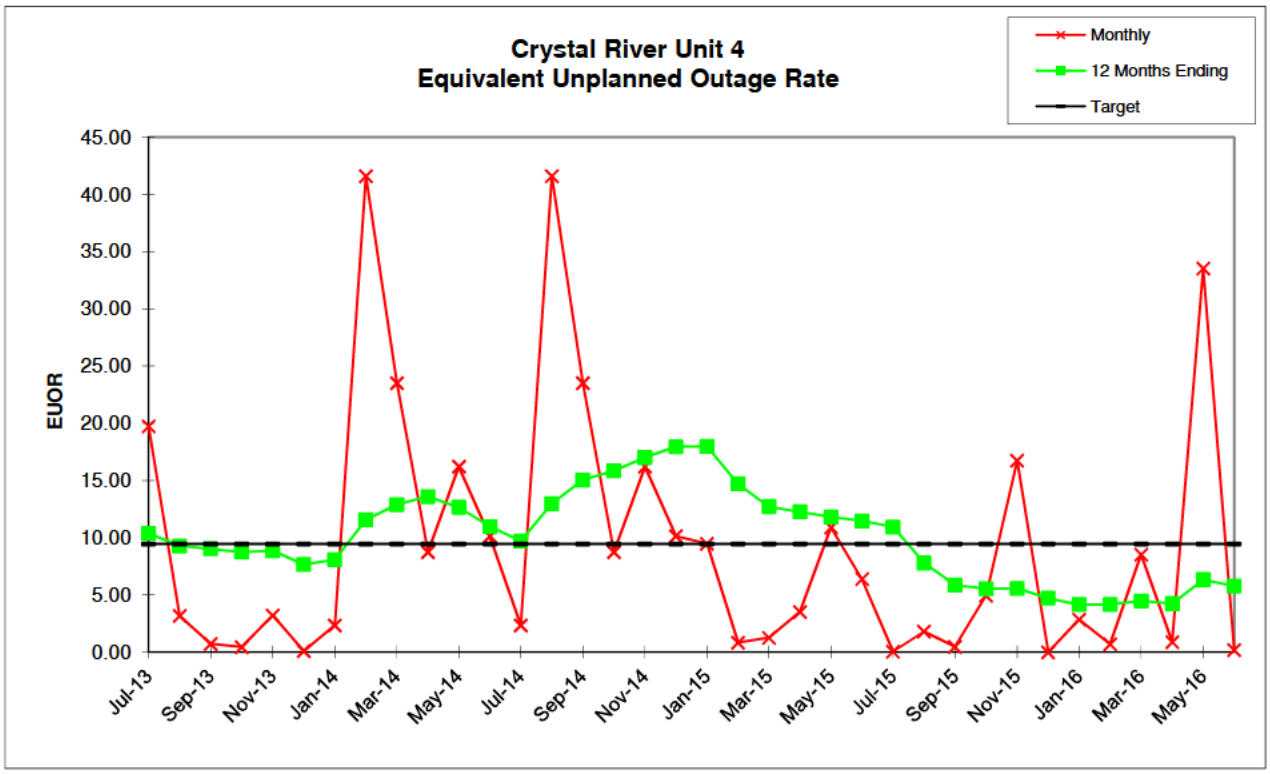
12 MONTHS	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**
FOR	11.83	8.38	7.53	6.75	6.70	5.81	5.58	2.30	1.60	0.91	0.91	0.05	0.30	0.30	0.32	0.32	0.33	0.33
MOR	7.19	6.93	5.39	5.35	4.51	4.95	4.75	4.56	3.20	3.17	3.12	3.09	2.31	2.32	2.51	2.51	4.93	4.46
PFOR	0.34	0.31	0.33	0.44	0.39	0.44	0.42	0.41	0.40	0.39	0.35	0.35	0.35	0.29	0.28	0.16	0.22	0.17
PMOR	0.27	0.22	0.30	0.51	0.91	0.96	0.80	0.80	0.82	1.18	1.28	1.27	1.25	1.31	1.42	1.29	0.94	0.90
EUOR	17.97	14.69	12.71	12.26	11.79	11.47	10.92	7.79	5.85	5.54	5.56	4.71	4.14	4.16	4.47	4.23	6.33	5.77
EUOF	17.29	14.13	12.23	11.80	11.34	11.03	10.92	7.79	5.85	5.54	5.56	4.71	4.14	4.12	4.09	3.88	5.79	5.28
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	0.94	8.44	8.44	8.44	8.44
EAF	82.71	85.87	87.77	88.20	88.66	88.97	89.08	92.21	94.15	94.46	94.44	95.29	95.86	94.95	87.47	87.68	85.76	86.27

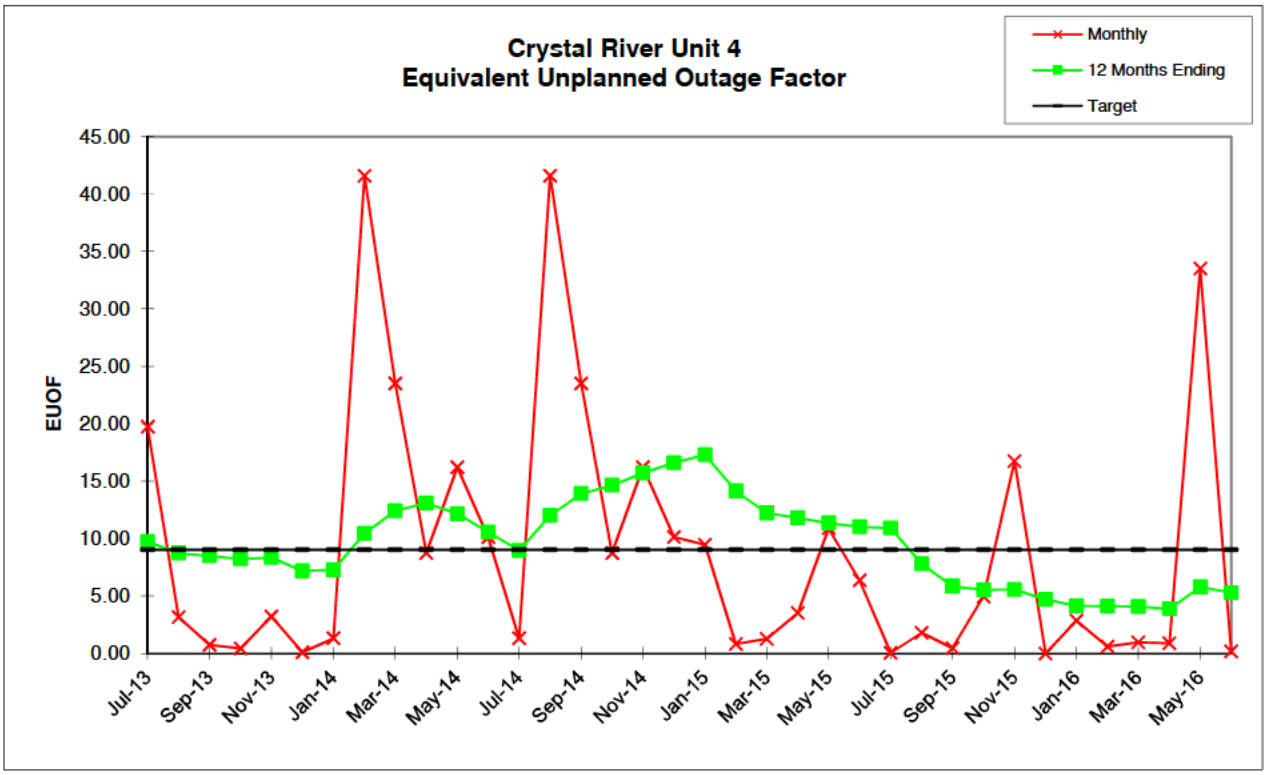

Crystal River Unit 4
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Crystal River Unit 4
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Crystal River Unit 4
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
2.50
2.00
1.50
1.00
0.50
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Crystal River Unit 4
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Crystal River Unit 4
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Crystal River 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
10.00
5.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16

Crystal River
Unit 5

	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
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	744.00	733.55	678.32	744.00	553.95	0.00	623.42	541.10	375.38	720.00	641.95	613.00	668.17	744.00	638.17	744.00	631.43	744.00
RSH	0.00	0.00	0.00	0.00	167.05	744.00	120.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	10.45	41.68	0.00	0.00	0.00	0.00	130.90	367.62	0.00	102.05	107.00	75.83	0.00	81.83	0.00	89.57	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	130.90	344.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	6.65	41.68	0.00	0.00	0.00	0.00	0.00	23.12	0.00	0.00	0.00	75.83	0.00	0.00	0.00	89.57	0.00
MOH	0.00	3.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	102.05	107.00	0.00	0.00	81.83	0.00	0.00	0.00
PFOH	9.18	18.00	0.00	0.00	0.00	0.00	0.00	0.00	6.75	12.85	4.10	2.23	0.00	1.67	3.33	4.25	20.37	2.25
LRPF	63.40	99.28	0.00	0.00	0.00	0.00	0.00	0.00	567.00	91.00	91.00	567.85	0.00	214.57	139.14	63.00	181.61	91.00
EFOH	0.82	2.52	0.00	0.00	0.00	0.00	0.00	0.00	5.39	1.65	0.53	1.78	0.00	0.50	0.65	0.38	5.21	0.29
PMOH	7.00	3.43	30.07	62.53	95.95	0.00	0.00	9.50	0.00	28.67	18.72	7.00	0.00	6.97	15.11	155.71	22.27	22.68
LRPM	91.00	472.46	151.56	57.57	77.62	0.00	0.00	234.00	0.00	72.43	90.98	91.00	0.00	100.95	143.09	73.91	156.81	91.01
EMOH	0.90	2.28	6.42	5.07	10.49	0.00	0.00	3.13	0.00	2.92	2.40	0.90	0.00	0.99	3.05	16.21	4.92	2.91
NPC	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00

MONTHLY	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**
FOR	0.00	0.90	5.79	0.00	0.00	0.00	0.00	0.00	5.80	0.00	0.00	0.00	10.19	0.00	0.00	0.00	12.42	0.00
MOR	0.00	0.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.72	14.86	0.00	0.00	11.37	0.00	0.00	0.00
PFOR	0.11	0.34	0.00	0.00	0.00	0.00	0.00	0.00	1.44	0.23	0.08	0.29	0.00	0.07	0.10	0.05	0.83	0.04
PMOR	0.12	0.31	0.95	0.68	1.89	0.00	0.00	0.58	0.00	0.41	0.37	0.15	0.00	0.13	0.48	2.18	0.78	0.39
EUOR	0.23	2.05	6.68	0.68	1.89	0.00	0.00	0.58	7.15	0.63	14.11	15.23	10.19	0.20	11.88	2.23	13.83	0.43
EUOF	0.23	2.05	6.68	0.68	1.45	0.00	0.00	0.47	3.84	0.63	14.11	15.23	10.19	0.20	11.88	2.23	13.83	0.43
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.48	46.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	99.77	97.95	93.32	99.32	98.55	100.00	100.00	80.05	49.80	99.37	85.89	84.77	89.81	99.80	88.12	97.77	86.17	99.57

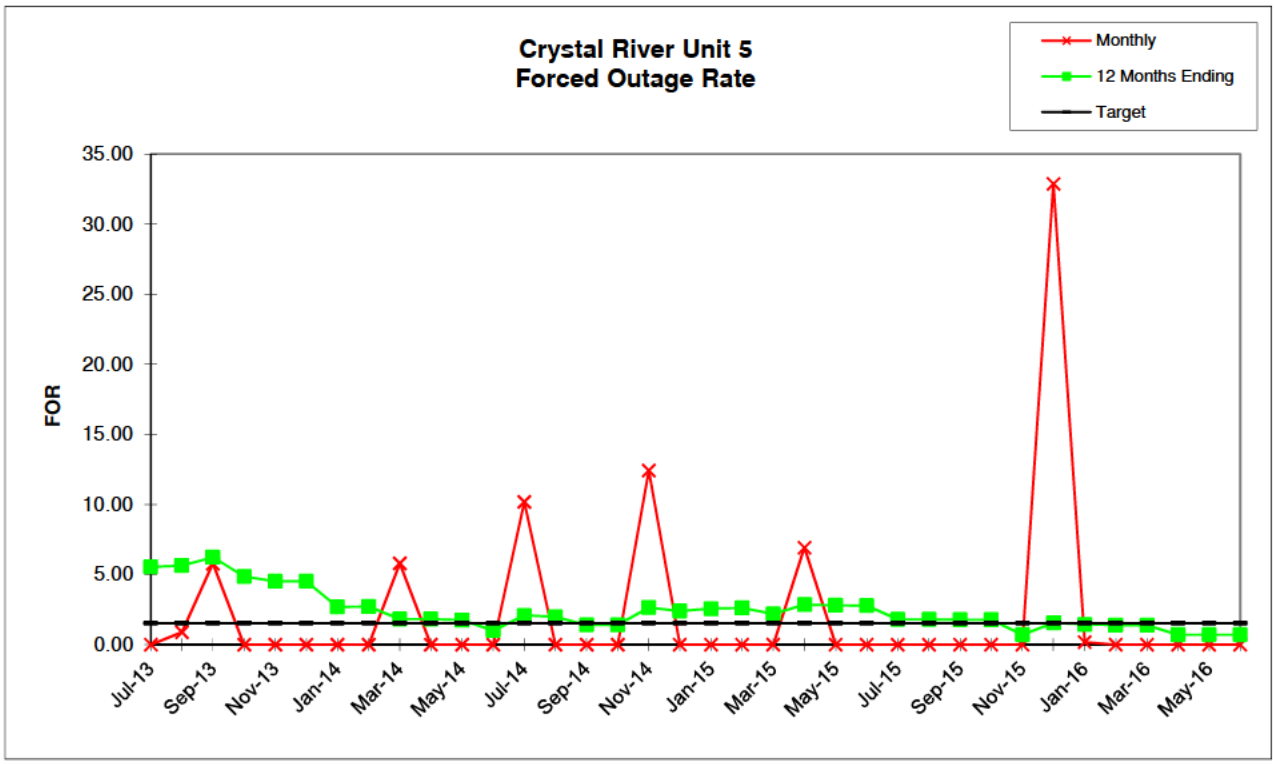
12 MONTHS	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**
FOR	5.55	5.65	6.23	4.86	4.52	4.53	2.70	2.73	1.83	1.83	1.75	1.01	2.09	2.00	1.42	1.42	2.64	2.39
MOR	0.54	0.60	0.60	0.59	0.54	0.54	0.54	0.05	0.05	0.05	1.49	2.96	3.00	2.94	4.07	4.07	4.02	3.65
PFOR	0.89	0.92	0.92	0.88	0.82	0.82	0.34	0.07	0.15	0.16	0.16	0.18	0.17	0.14	0.15	0.16	0.23	0.21
PMOR	0.42	0.32	0.33	0.38	0.50	0.50	0.49	0.42	0.42	0.45	0.49	0.50	0.49	0.47	0.42	0.58	0.50	0.49
EUOR	7.27	7.35	7.93	6.59	6.26	6.27	4.02	3.25	2.44	2.48	3.82	4.57	5.59	5.40	5.92	6.08	7.14	6.53
EUOF	5.97	6.03	6.51	5.50	5.62	5.62	3.55	2.82	2.02	2.05	3.16	3.78	4.63	4.47	4.90	5.03	6.05	6.09
POF	17.89	17.89	17.89	16.54	8.31	0.00	0.00	1.49	5.43	5.43	5.43	5.43	5.43	5.43	5.43	5.43	5.43	5.43
EAF	76.14	76.07	75.60	77.96	86.07	94.38	96.45	95.68	92.55	92.52	91.41	90.79	89.94	90.10	89.67	89.54	88.52	88.49

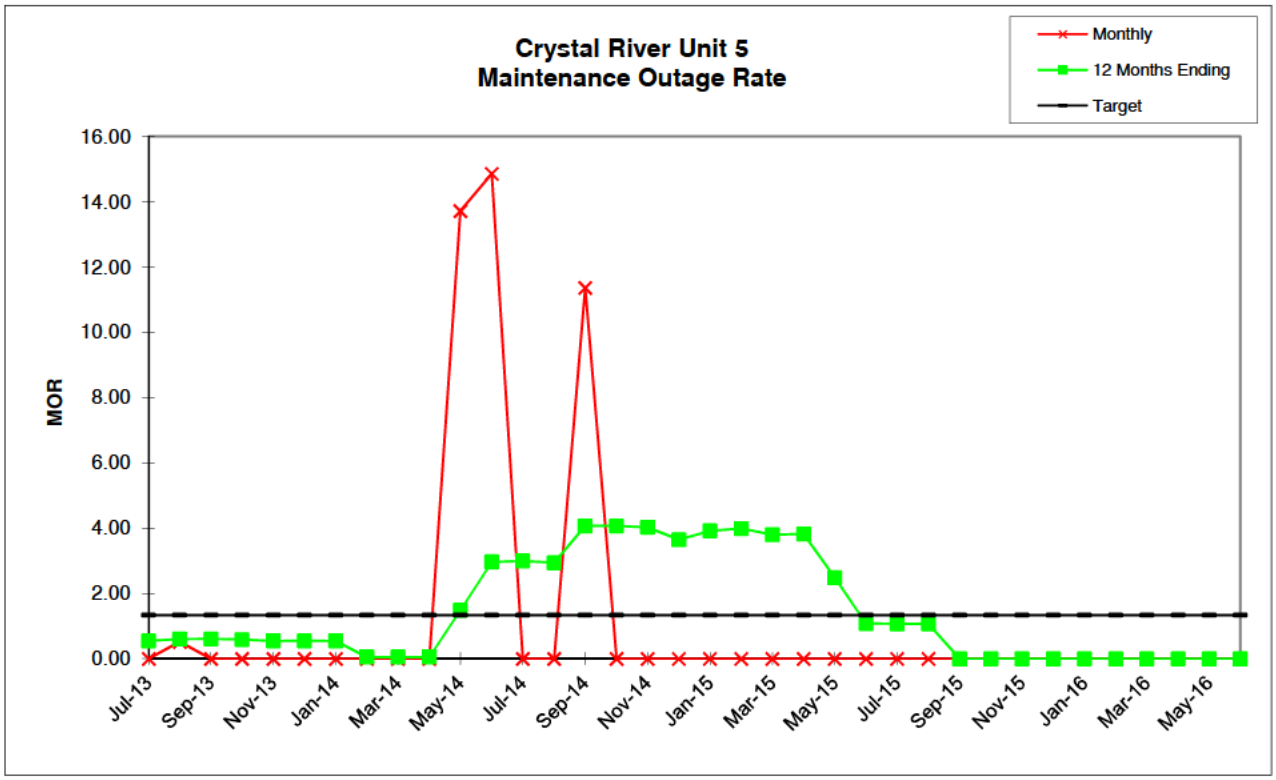
Crystal River
Unit 5

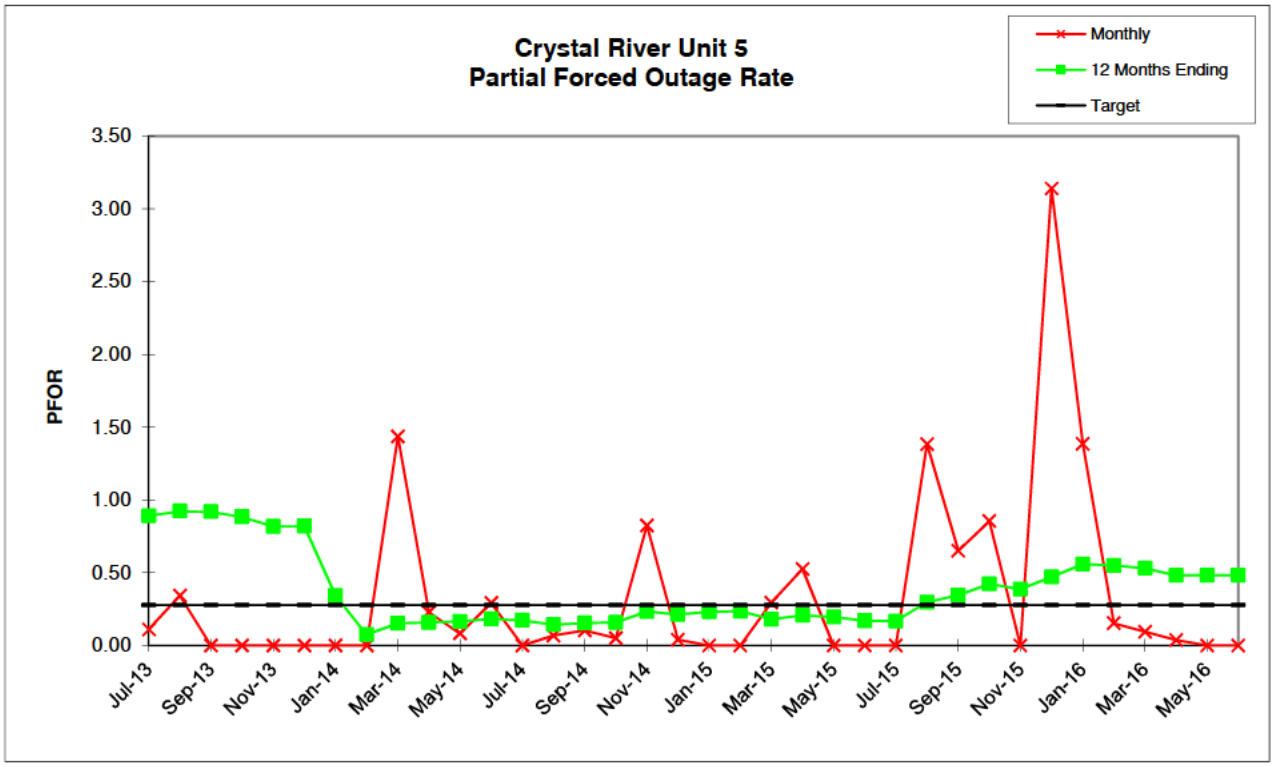
	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	696.00	743.00	720.00	744.00	720.00
SER HOURS	75.32	404.02	743.00	670.08	744.00	720.00	744.00	744.00	720.00	719.98	0.00	104.30	618.47	696.00	743.00	720.00	744.00	720.00
RSH	668.68	267.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	217.00	588.60	124.38	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	0.00	49.92	0.00	0.00	0.00	0.00	0.00	24.02	504.00	51.10	1.15	0.00	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	24.02	504.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	49.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	51.10	1.15	0.00	0.00	0.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	0.00	17.01	28.28	0.00	0.00	0.00	41.84	22.99	9.25	0.00	43.90	20.02	8.26	5.45	3.00	0.00	0.00
LRPF	0.00	0.00	91.04	88.40	0.00	0.00	0.00	174.52	144.53	472.00	0.00	53.00	303.68	91.07	91.00	63.00	0.00	0.00
EFOH	0.00	0.00	2.18	3.52	0.00	0.00	0.00	10.28	4.68	6.15	0.00	3.28	8.56	1.06	0.70	0.27	0.00	0.00
PMOH	0.00	3.67	24.86	52.97	65.27	33.61	12.00	17.98	23.07	39.61	0.00	3.00	3.63	58.14	10.50	16.91	2.75	40.17
LRPM	0.00	471.57	177.54	78.48	199.38	83.63	63.00	80.35	292.06	124.01	0.00	472.00	63.06	152.69	345.00	126.26	567.00	148.78
EMOH	0.00	2.44	6.22	5.85	18.33	3.96	1.06	2.03	9.49	6.92	0.00	1.99	0.32	12.50	5.10	3.01	2.20	8.42
NPC	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00	710.00

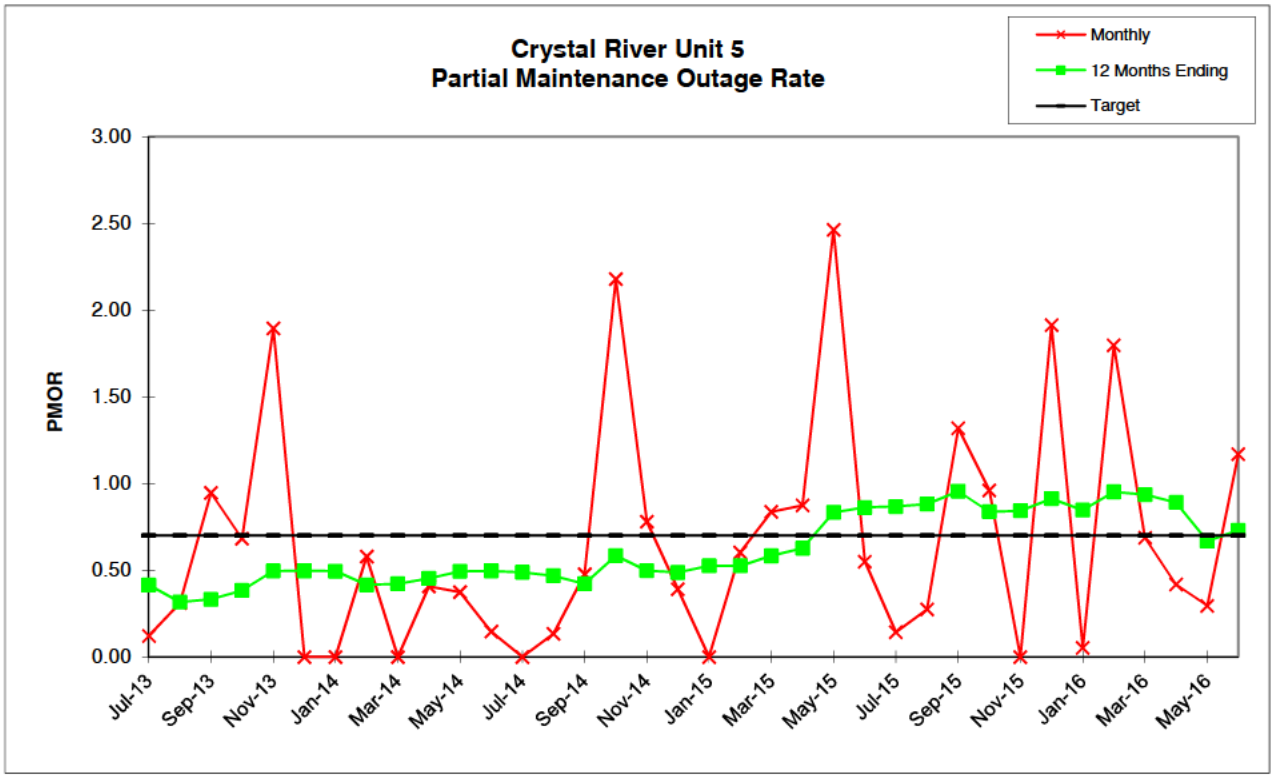
MONTHLY	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**
FOR	0.00	0.00	0.00	6.93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.88	0.19	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.00	0.29	0.53	0.00	0.00	0.00	1.38	0.65	0.85	0.00	3.14	1.38	0.15	0.09	0.04	0.00	0.00
PMOR	0.00	0.60	0.84	0.87	2.46	0.55	0.14	0.27	1.32	0.96	0.00	1.91	0.05	1.80	0.69	0.42	0.30	1.17
EUOR	0.00	0.60	1.13	8.24	2.46	0.55	0.14	1.66	1.97	1.82	0.00	36.28	1.62	1.95	0.78	0.45	0.30	1.17
EUOF	0.00	0.36	1.13	8.24	2.46	0.55	0.14	1.66	1.97	1.76	0.00	7.58	1.35	1.95	0.78	0.45	0.30	1.17
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.23	69.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	100.00	99.64	98.87	91.76	97.54	99.45	99.86	98.34	98.03	95.02	30.10	92.42	98.65	98.05	99.22	99.55	99.70	98.83

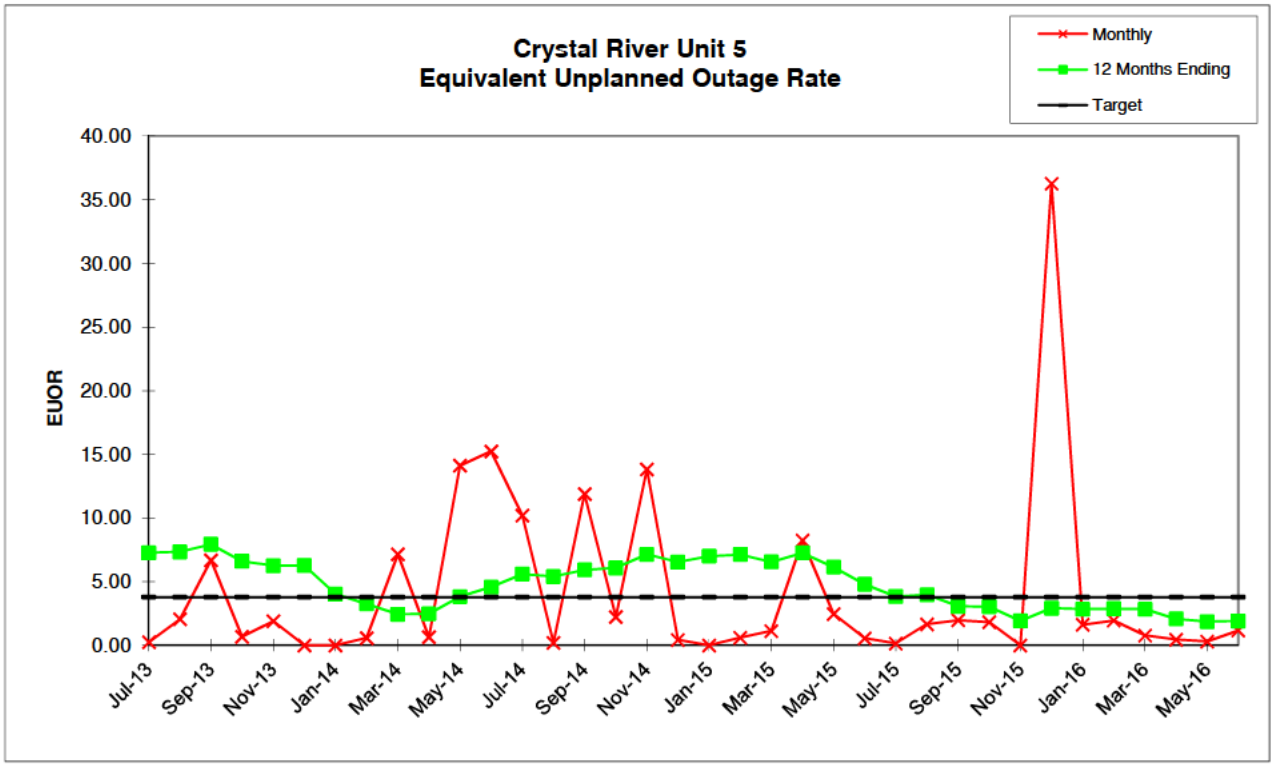
12 MONTHS	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**
FOR	2.57	2.62	2.20	2.86	2.82	2.78	1.80	1.80	1.78	1.79	0.71	1.56	1.45	1.39	1.39	0.71	0.71	0.71
MOR	3.92	3.99	3.80	3.82	2.48	1.08	1.06	1.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.23	0.23	0.18	0.21	0.20	0.17	0.17	0.30	0.35	0.42	0.39	0.47	0.56	0.55	0.53	0.48	0.48	0.48
PMOR	0.52	0.52	0.58	0.63	0.83	0.86	0.87	0.88	0.96	0.84	0.84	0.91	0.85	0.95	0.94	0.89	0.67	0.73
EUOR	7.00	7.12	6.55	7.25	6.14	4.79	3.83	3.97	3.06	3.03	1.92	2.92	2.84	2.87	2.84	2.07	1.85	1.91
EUOF	6.09	6.08	5.85	6.47	5.48	4.28	3.42	3.55	2.73	2.69	1.56	2.16	2.28	2.40	2.37	1.73	1.55	1.60
POF	5.43	3.93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.27	6.03	6.03	6.03	6.01	6.01	6.01	6.01	6.01
EAF	88.49	89.99	94.15	93.53	94.52	95.72	96.58	96.45	97.27	97.03	92.42	91.81	91.70	91.59	91.62	92.26	92.44	92.39

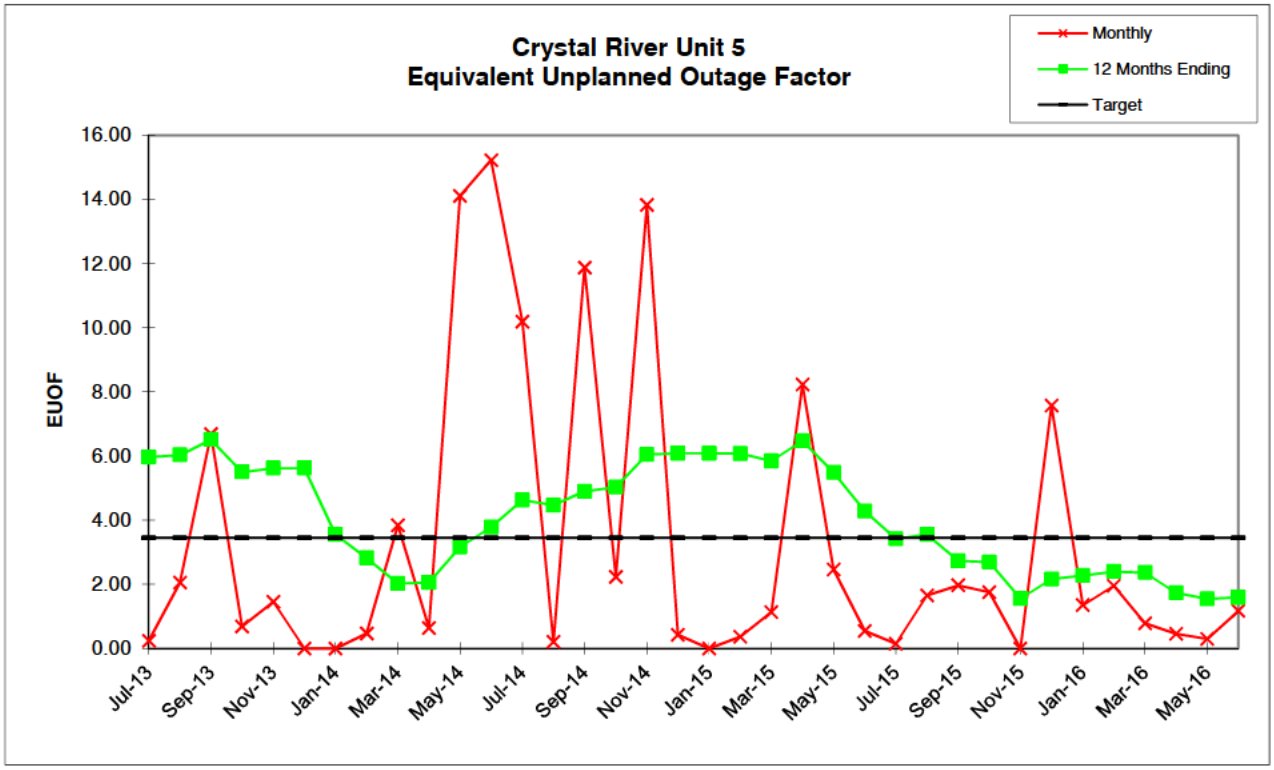

Crystal River Unit 5
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Crystal River Unit 5
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Crystal River Unit 5
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Crystal River Unit 5
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Crystal River Unit 5
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Crystal River Unit 5
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16

Hines
Unit 1

	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
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	744.00	744.00	720.00	744.00	358.67	0.00	631.51	672.00	600.98	202.74	734.24	720.00	702.04	742.67	715.74	691.80	721.00	744.00
RSH	0.00	0.00	0.00	0.00	360.55	744.00	112.49	0.00	142.02	517.26	3.78	0.00	7.59	0.00	0.01	18.22	0.00	0.00
UH	0.00	0.00	0.00	0.00	1.78	0.00	0.00	0.00	0.00	0.00	5.98	0.00	34.37	1.33	4.24	33.98	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	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	1.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.33	4.24	33.98	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.98	0.00	34.37	0.00	0.00	0.00	0.00	0.00
PFOH	55.30	45.51	0.00	0.00	10.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.41	0.00	33.84	0.00	0.00
LRPF	169.59	246.96	0.00	0.00	347.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	86.26	0.00	83.13	0.00	0.00
EFOH	20.30	24.33	0.00	0.00	7.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.26	0.00	6.05	0.00	0.00
PMOH	0.00	1.38	71.19	1.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.25	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	199.48	227.48	199.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	62.78	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.60	35.05	0.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.87	0.00	0.00	0.00	0.00	0.00	0.00
NPC	462.00	462.00	462.00	462.00	462.00	462.00	465.00	465.00	465.00	465.00	465.00	465.00	465.00	465.00	465.00	465.00	465.00	465.00

MONTHLY	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**
FOR	0.00	0.00	0.00	0.00	0.49	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.18	0.59	4.68	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.81	0.00	4.67	0.00	0.00	0.00	0.00	0.00
PFOR	2.73	3.27	0.00	0.00	2.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.87	0.00	0.00
PMOR	0.00	0.08	4.87	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	2.73	3.35	4.87	0.08	2.61	0.00	0.00	0.00	0.00	0.00	0.81	0.40	4.67	0.21	0.59	5.52	0.00	0.00
EUOF	2.73	3.35	4.87	0.08	1.30	0.00	0.00	0.00	0.00	0.00	0.80	0.40	4.62	0.21	0.59	5.38	0.00	0.00
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	97.27	96.65	95.13	99.92	98.70	100.00	100.00	100.00	100.00	100.00	99.20	99.60	95.38	99.79	99.41	94.62	100.00	100.00

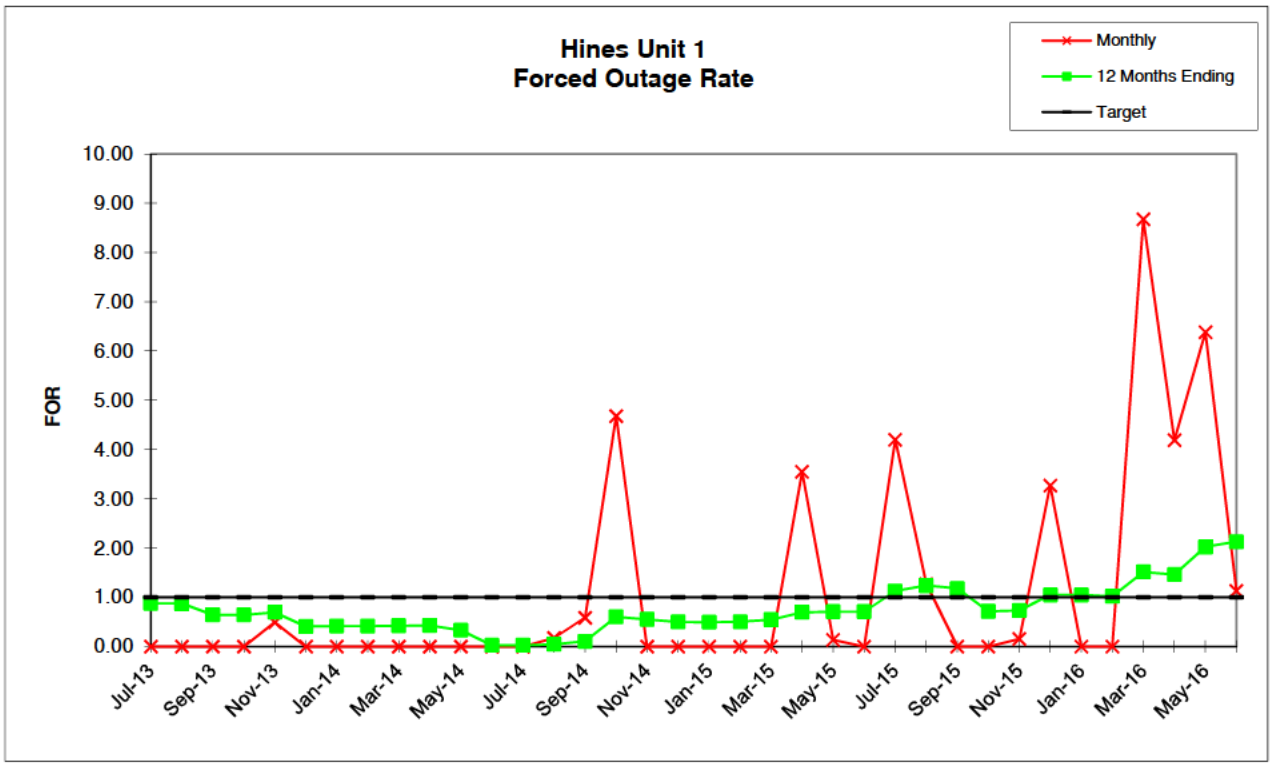
12 MONTHS	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**
FOR	0.88	0.88	0.64	0.64	0.70	0.41	0.42	0.42	0.42	0.43	0.33	0.03	0.03	0.05	0.11	0.61	0.55	0.50
MOR	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.09	0.59	0.59	0.59	0.59	0.56	0.51
PFOR	0.60	0.73	0.73	0.73	0.86	0.95	0.96	0.96	0.98	0.99	0.97	0.76	0.47	0.12	0.12	0.21	0.09	0.08
PMOR	0.27	0.27	0.69	0.70	0.48	0.53	0.53	0.53	0.54	0.55	0.54	0.57	0.57	0.56	0.05	0.04	0.04	0.04
EUOR	2.04	1.86	2.05	2.06	2.02	1.87	1.90	1.90	1.94	1.97	1.92	1.44	1.65	1.31	0.86	1.44	1.23	1.12
EUOF	1.90	1.73	1.91	1.92	1.80	1.51	1.51	1.51	1.51	1.51	1.51	1.13	1.29	1.03	0.67	1.12	1.02	1.02
POF	6.84	6.84	6.84	6.84	6.84	6.84	6.84	6.84	6.84	1.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	91.26	91.43	91.25	91.25	91.36	91.65	91.65	91.65	91.65	96.54	98.49	98.87	98.71	98.97	99.33	98.88	98.98	98.98

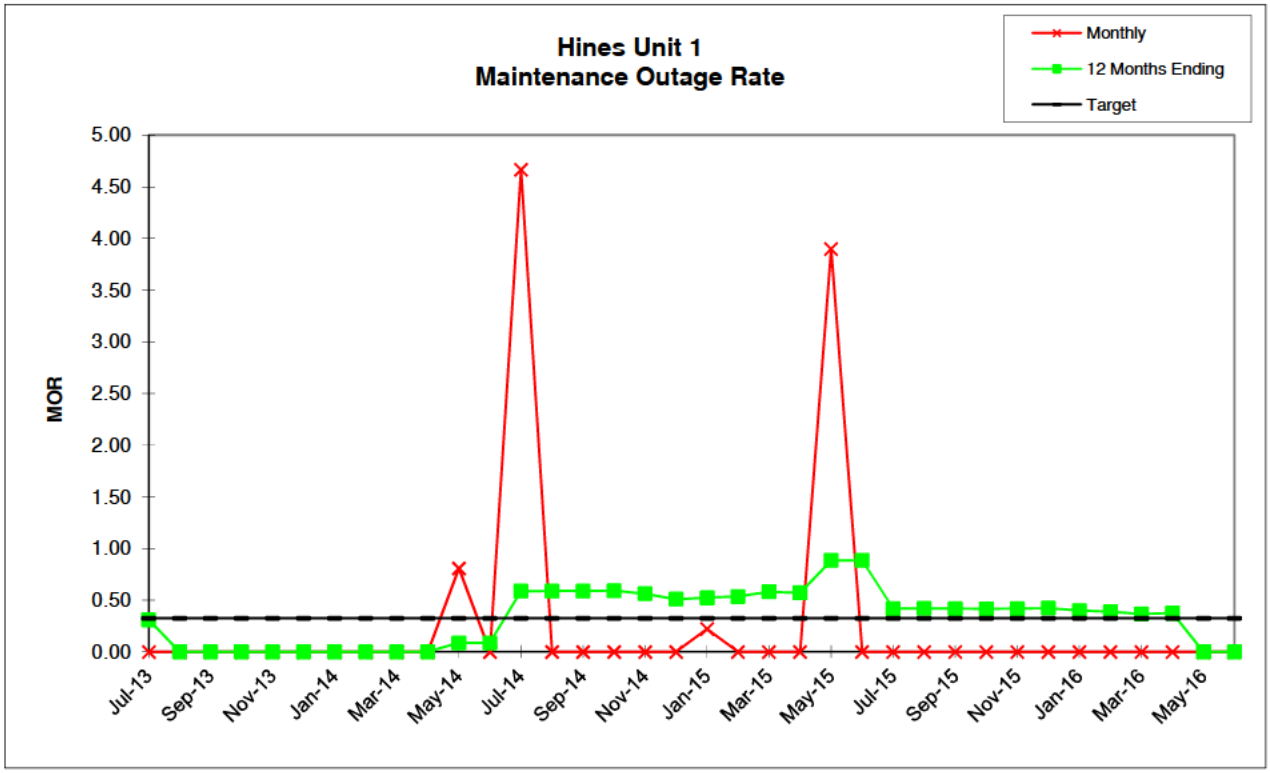
Hines
Unit 1

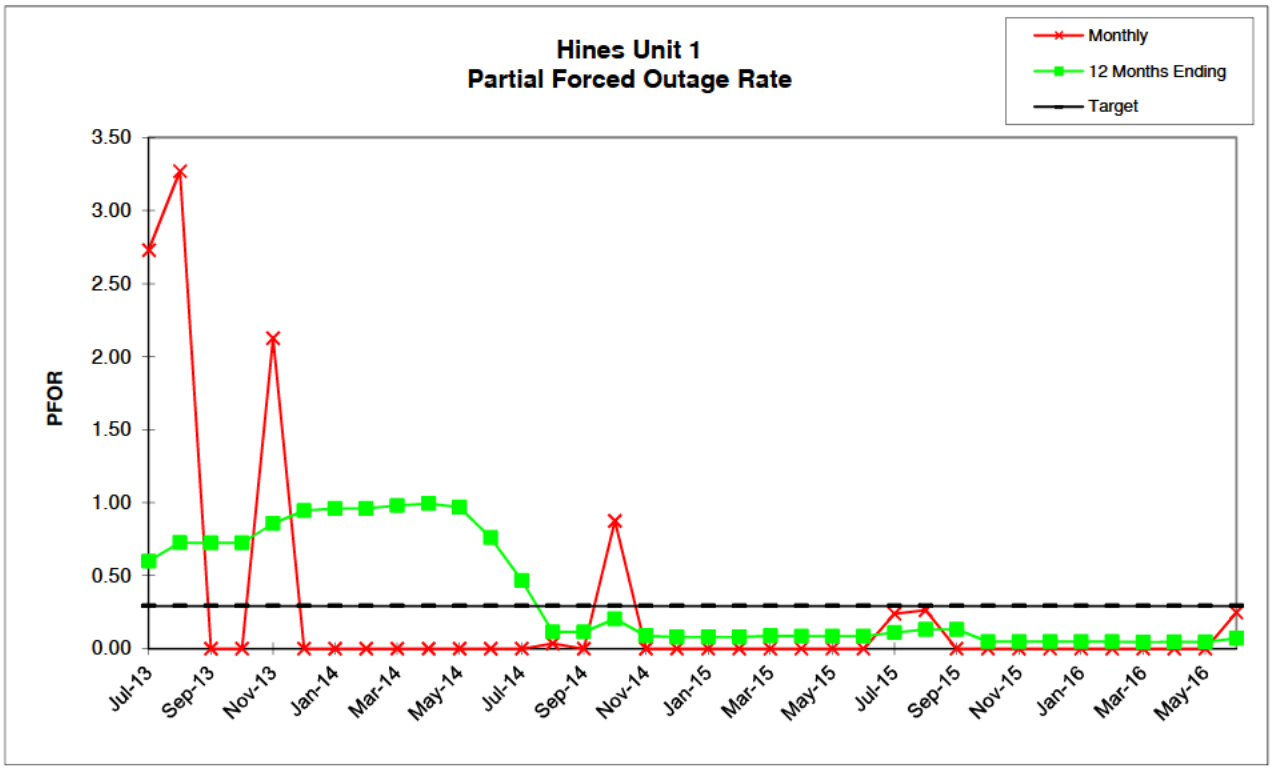
	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	696.00	743.00	720.00	744.00	720.00
SER HOURS	737.13	478.48	0.00	316.33	714.04	720.00	706.52	732.17	720.00	744.00	685.05	668.16	744.00	696.00	477.66	92.41	649.99	711.86
RSH	5.23	2.77	0.00	0.00	0.00	0.00	6.50	2.40	0.00	0.00	34.88	53.24	0.00	0.00	5.23	0.00	0.01	0.00
UH	1.63	190.75	743.00	403.67	29.96	0.00	30.98	9.43	0.00	0.00	1.07	22.60	0.00	0.00	260.11	627.59	94.01	8.14
POH	0.00	190.75	743.00	392.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	214.75	623.55	49.71	0.00
FOH	0.00	0.00	0.00	11.64	0.98	0.00	30.98	9.43	0.00	0.00	1.07	22.60	0.00	0.00	45.36	4.04	44.30	8.14
MOH	1.63	0.00	0.00	0.00	28.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	0.00	0.00	0.00	0.00	0.00	8.82	10.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.63
LRPF	0.00	0.00	0.00	0.00	0.00	0.00	89.05	81.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	106.39
EFOH	0.00	0.00	0.00	0.00	0.00	0.00	1.70	1.93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.77
PMOH	15.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	71.99	0.00	0.00	0.00	0.00	0.00	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	2.08	0.00	0.00	0.00	0.00	0.00	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	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	462.00	518.00	518.00	518.00	518.00	518.00	518.00

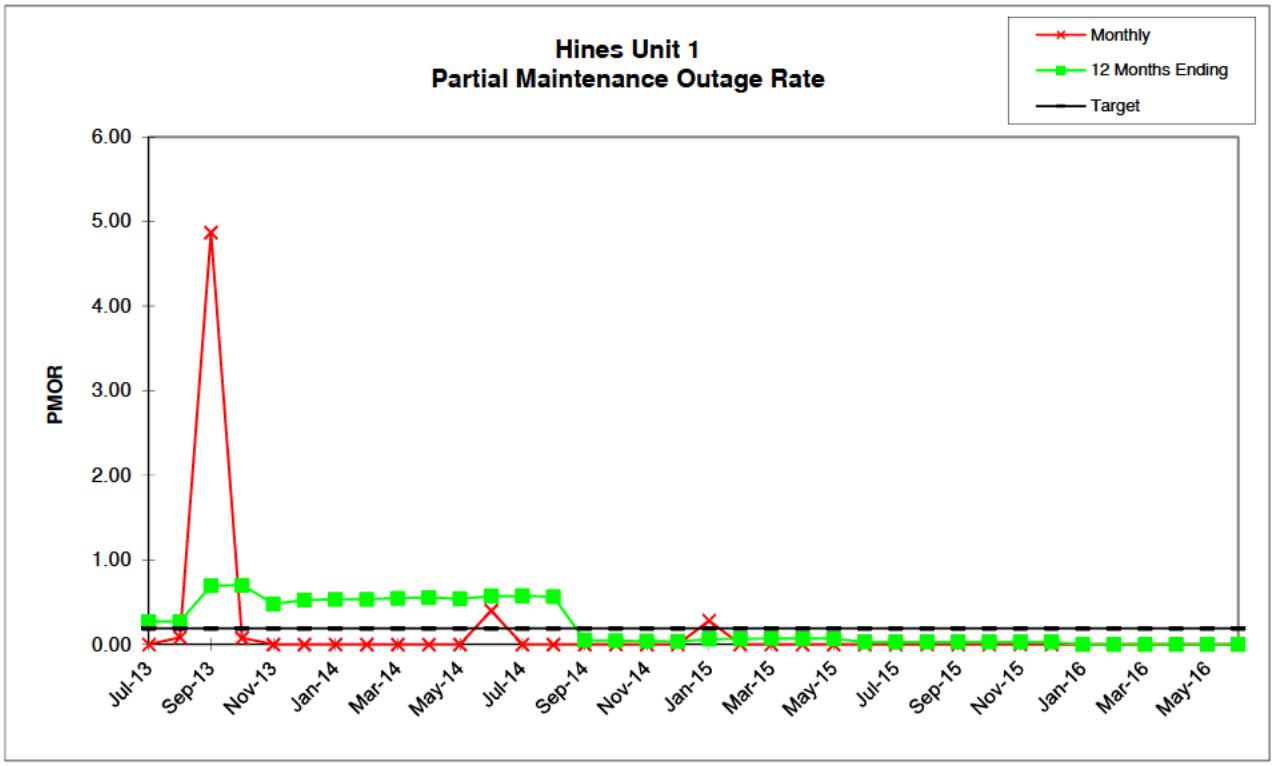
MONTHLY	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**
FOR	0.00	0.00	0.00	3.55	0.14	0.00	4.20	1.27	0.00	0.00	0.16	3.27	0.00	0.00	8.67	4.19	6.38	1.13
MOR	0.22	0.00	0.00	0.00	3.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.24	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.25
PMOR	0.28	0.00	0.00	0.00	0.00	0.00	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	0.50	0.00	0.00	3.55	4.03	0.00	4.43	1.53	0.00	0.00	0.16	3.27	0.00	0.00	8.67	4.19	6.38	1.38
EUOF	0.50	0.00	0.00	1.62	4.03	0.00	4.39	1.53	0.00	0.00	0.15	3.04	0.00	0.00	6.10	0.56	5.95	1.38
POF	0.00	28.39	100.00	54.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.90	86.60	6.68	0.00
EAF	99.50	71.61	0.00	43.94	95.97	100.00	95.61	98.47	100.00	100.00	99.85	96.96	100.00	100.00	64.99	12.83	87.36	98.62

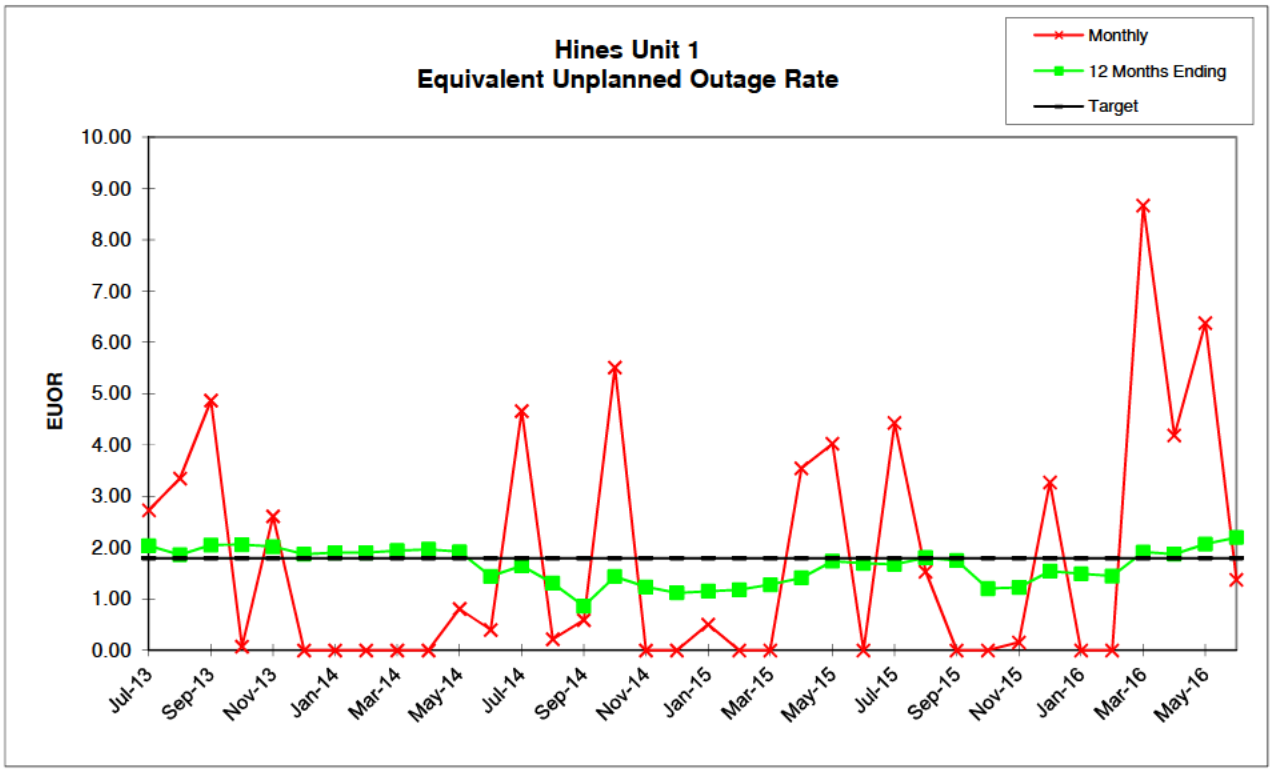
12 MONTHS	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**
FOR	0.49	0.51	0.55	0.70	0.71	0.71	1.13	1.24	1.18	0.72	0.74	1.05	1.05	1.02	1.52	1.46	2.02	2.13
MOR	0.52	0.54	0.58	0.57	0.88	0.88	0.42	0.42	0.42	0.42	0.42	0.42	0.40	0.39	0.36	0.37	0.00	0.00
PFOR	0.08	0.08	0.09	0.09	0.09	0.09	0.11	0.13	0.13	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.07
PMOR	0.06	0.06	0.07	0.07	0.07	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	1.15	1.18	1.28	1.41	1.74	1.70	1.67	1.81	1.75	1.20	1.22	1.54	1.49	1.45	1.92	1.88	2.07	2.20
EUOF	1.06	1.06	1.06	1.19	1.47	1.43	1.41	1.53	1.48	1.02	1.03	1.29	1.25	1.24	1.76	1.67	1.84	1.95
POF	0.00	2.18	10.66	15.13	15.13	15.13	15.13	15.13	15.13	15.13	15.13	15.13	15.13	12.92	6.91	9.54	10.11	10.11
EAF	98.94	96.76	88.28	83.67	83.40	83.43	83.45	83.34	83.39	83.85	83.83	83.58	83.62	85.83	91.33	88.78	88.05	87.94

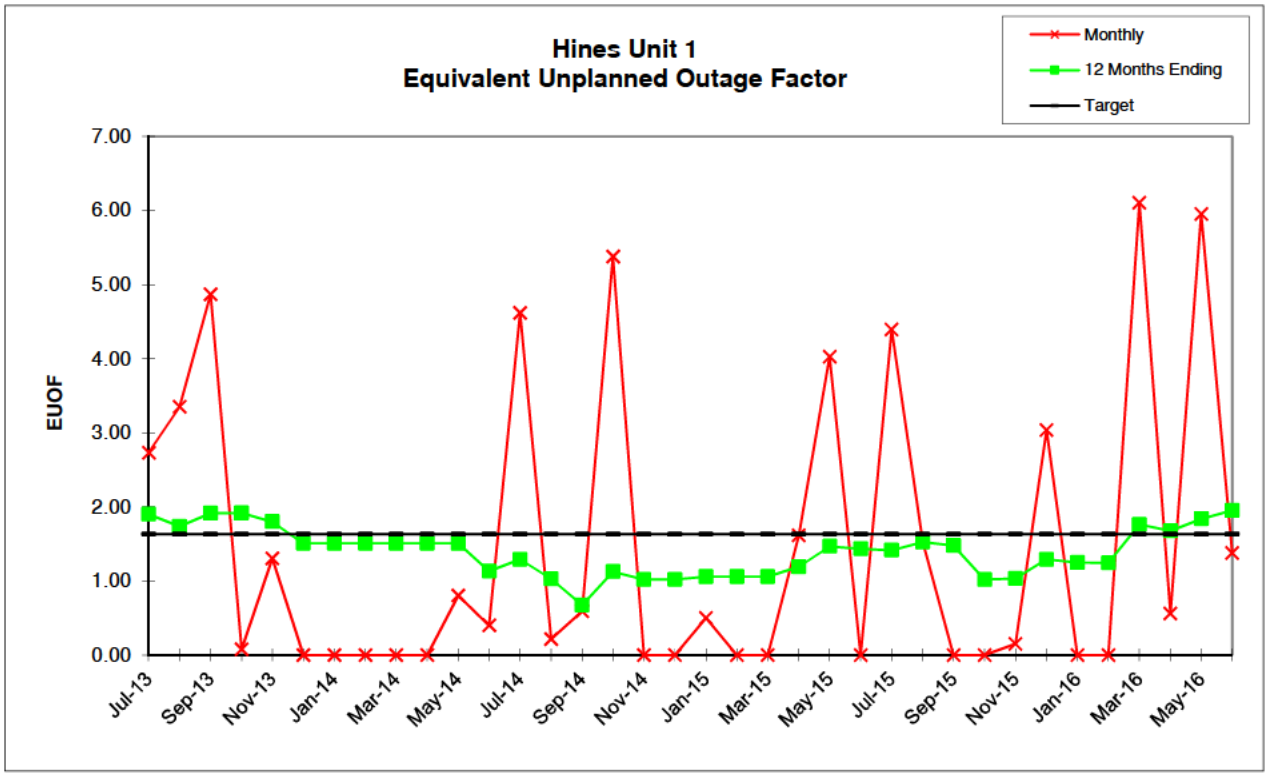

Hines Unit 1
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Hines Unit 1
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
5.00
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Hines Unit 1
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Hines Unit 1
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Hines Unit 1
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Hines Unit 1
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16

Hines
Unit 2

	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
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	744.00	744.00	720.00	744.00	721.00	739.62	536.53	114.32	629.49	720.00	722.88	690.99	159.08	0.00	0.00	0.00	0.00	0.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	205.18	557.68	113.51	0.00	0.00	17.64	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	0.00	0.00	0.00	4.38	2.29	0.00	0.00	0.00	21.12	11.37	584.92	744.00	720.00	744.00	721.00	744.00
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	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	4.38	2.29	0.00	0.00	0.00	21.12	1.84	584.92	744.00	720.00	744.00	721.00	744.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.53	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	22.66	0.00	1.12	0.00	0.00	61.05	2.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPF	230.33	0.00	313.06	0.00	0.00	1.00	123.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EFOH	10.65	0.00	0.72	0.00	0.00	0.12	0.68	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	1.50	1.10	0.00	0.00	0.00	0.00	0.00	0.94	0.00	6.03	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	136.00	136.00	0.00	0.00	0.00	0.00	0.00	51.88	0.00	55.63	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.42	0.31	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.68	0.00	0.00	0.00	0.00	0.00	0.00
NPC	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00

MONTHLY	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
FOR	0.00	0.00	0.00	0.00	0.00	0.59	0.43	0.00	0.00	0.00	2.84	0.27	78.62	100.00	100.00	100.00	100.00	100.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.36	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	1.43	0.00	0.10	0.00	0.00	0.02	0.13	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	0.06	0.04	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	1.43	0.00	0.16	0.04	0.00	0.61	0.55	0.00	0.00	0.01	2.84	1.72	78.62	100.00	100.00	100.00	100.00	100.00
EUOF	1.43	0.00	0.16	0.04	0.00	0.61	0.40	0.00	0.00	0.01	2.84	1.67	78.62	100.00	100.00	100.00	100.00	100.00
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	0.00	0.00	0.00	0.00
EAF	98.57	100.00	99.84	99.96	100.00	99.39	99.60	100.00	100.00	99.99	97.16	98.33	21.38	0.00	0.00	0.00	0.00	0.00

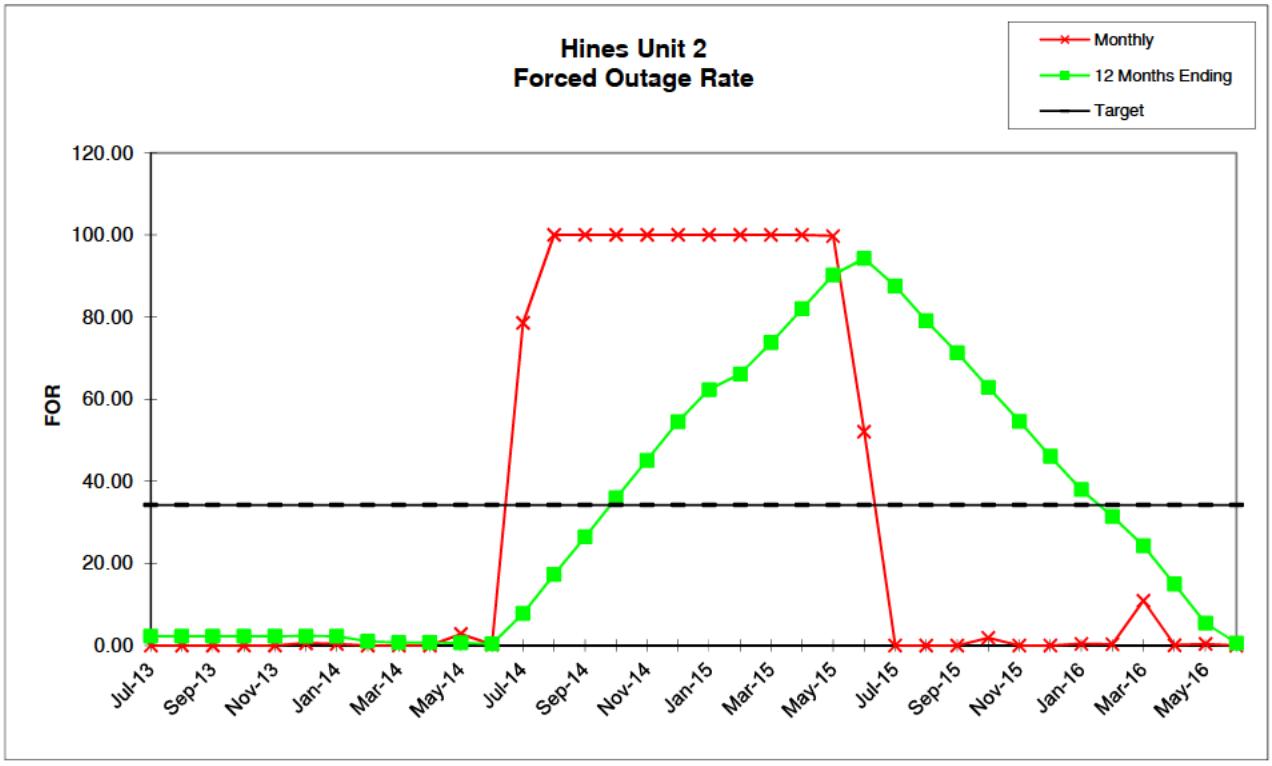
12 MONTHS	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
FOR	2.26	2.26	2.26	2.26	2.26	2.31	2.28	1.03	0.72	0.72	0.65	0.38	7.82	17.29	26.46	35.93	45.10	54.52
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.13	0.15	0.16	0.19	0.22	0.27
PFOR	0.14	0.14	0.15	0.15	0.15	0.15	0.16	0.15	0.16	0.16	0.16	0.16	0.02	0.02	0.01	0.02	0.02	0.02
PMOR	0.03	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
EUOR	2.42	2.41	2.42	2.43	2.42	2.47	2.45	1.20	0.89	0.89	0.82	0.67	7.97	17.43	26.57	36.02	45.19	54.59
EUOF	2.17	2.16	2.16	2.17	2.16	2.21	2.25	1.09	0.80	0.80	0.74	0.60	7.16	15.65	23.86	32.35	40.58	49.02
POF	5.66	5.66	5.66	5.66	5.66	5.66	5.66	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	92.18	92.18	92.18	92.17	92.18	92.13	92.10	98.91	99.20	99.20	99.26	99.40	92.84	84.35	76.14	67.65	59.42	50.98

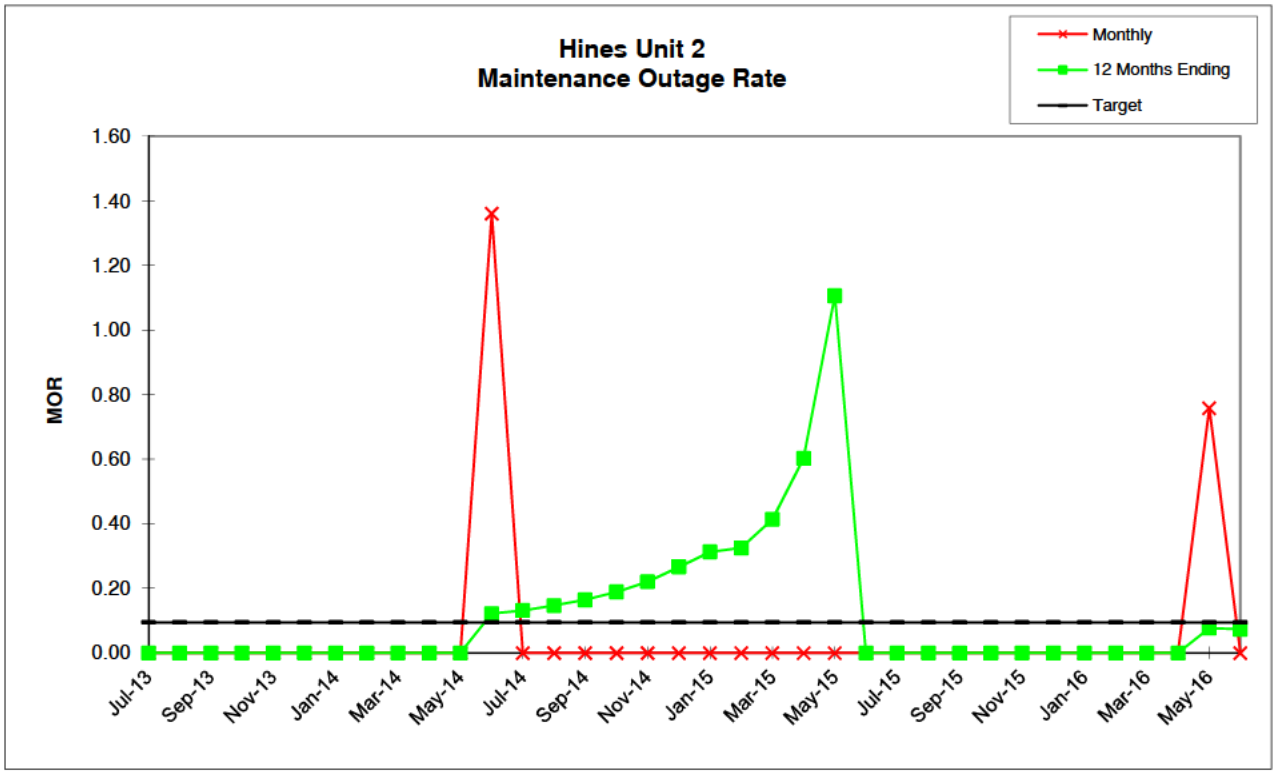
Hines
Unit 2

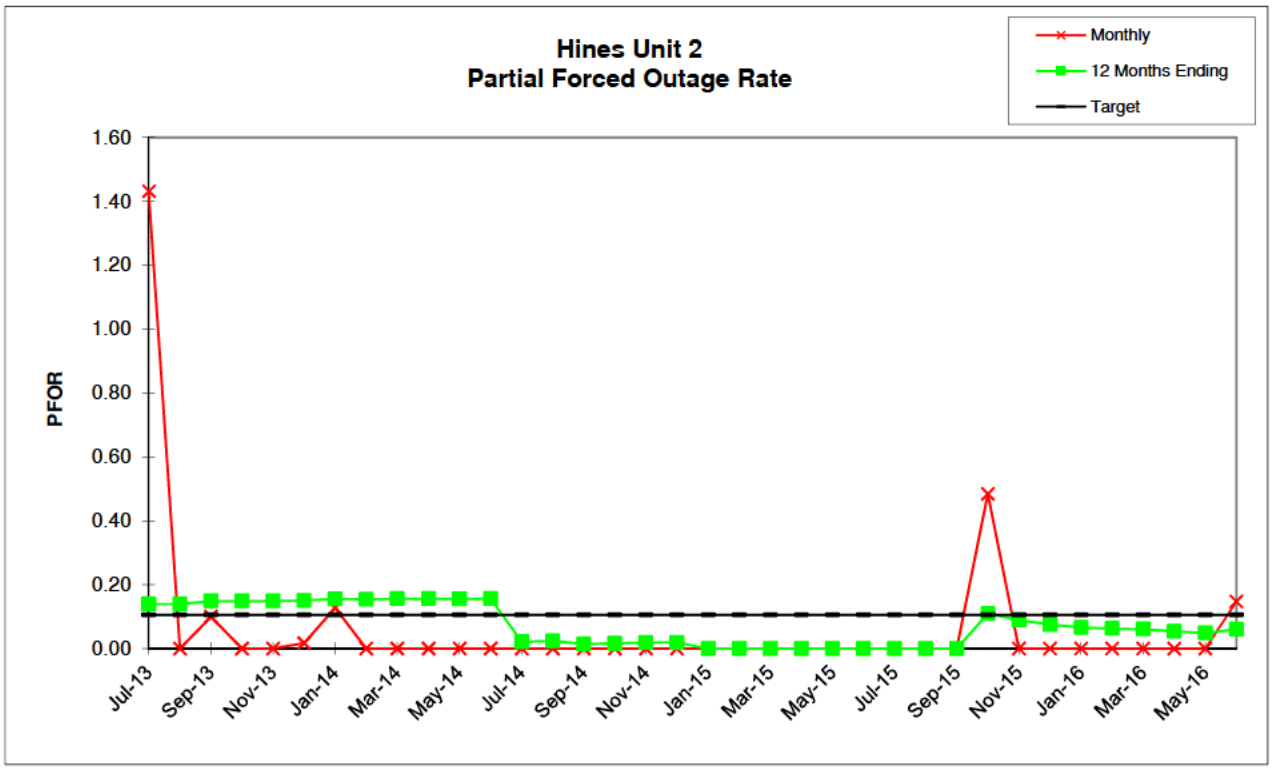
	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	696.00	743.00	720.00	744.00	720.00
SER HOURS	0.00	0.00	0.00	0.00	1.83	344.66	744.00	744.00	672.05	729.94	714.97	743.09	649.76	316.33	191.63	719.02	735.25	720.00
RSH	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	47.95	0.00	6.03	0.91	91.38	138.59	0.94	0.00	0.00	0.00
UH	744.00	672.00	743.00	720.00	742.17	375.33	0.00	0.00	0.00	14.06	0.00	0.00	2.86	241.08	550.43	0.98	8.75	0.00
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	240.00	526.97	0.00	0.00	0.00
FOH	744.00	672.00	743.00	720.00	742.17	375.33	0.00	0.00	0.00	14.06	0.00	0.00	2.86	1.08	23.46	0.98	3.13	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.62	0.00
PFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.49
LRPF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	104.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.79
EFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.06
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	563.00	563.00	563.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	490.00	546.00	546.00	546.00	546.00	546.00	546.00

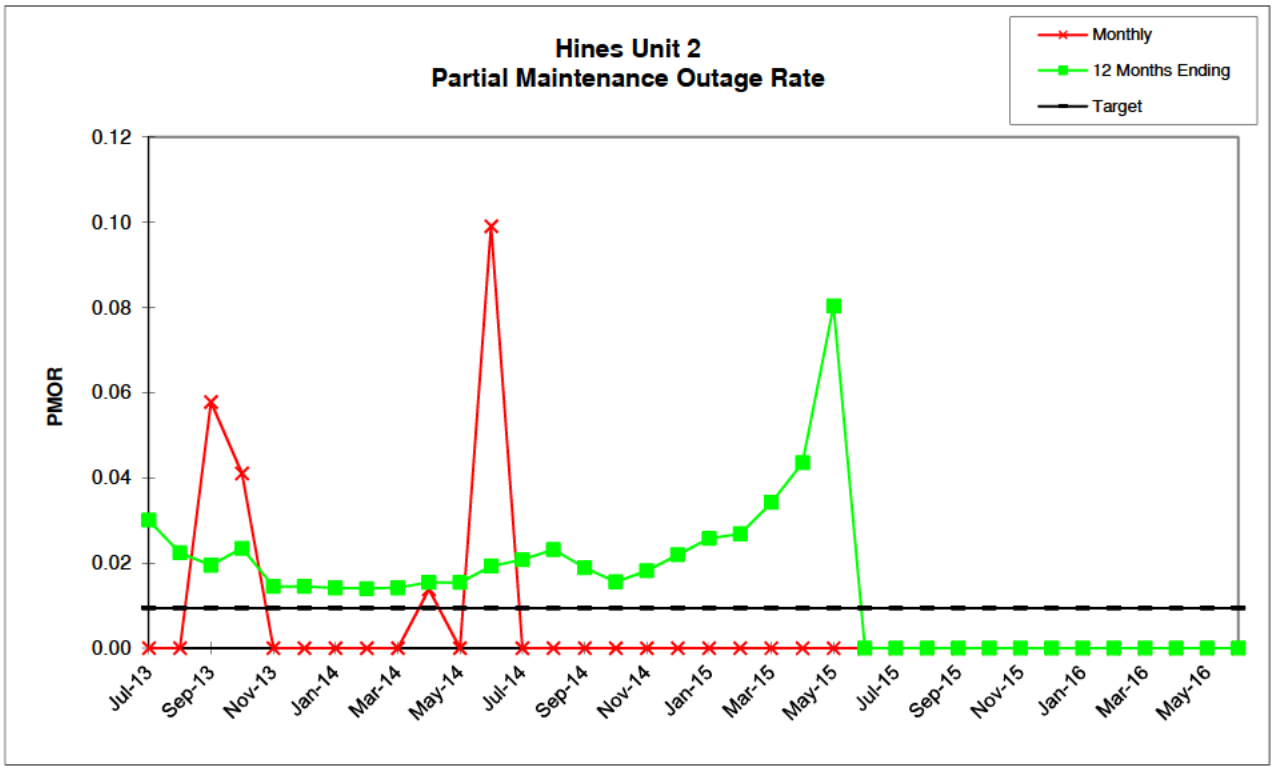
MONTHLY	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
FOR	100.00	100.00	100.00	100.00	99.75	52.13	0.00	0.00	0.00	1.89	0.00	0.00	0.44	0.34	10.91	0.14	0.42	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.76	0.00
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15
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	100.00	100.00	100.00	99.75	52.13	0.00	0.00	0.00	2.36	0.00	0.00	0.44	0.34	10.91	0.14	1.18	0.15
EUOF	100.00	100.00	100.00	100.00	99.75	52.13	0.00	0.00	0.00	2.36	0.00	0.00	0.38	0.16	3.16	0.14	1.18	0.15
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	34.48	70.92	0.00	0.00	0.00
EAF	0.00	0.00	0.00	0.00	0.25	47.87	100.00	100.00	100.00	97.64	100.00	100.00	99.62	65.36	25.92	99.86	98.82	99.85

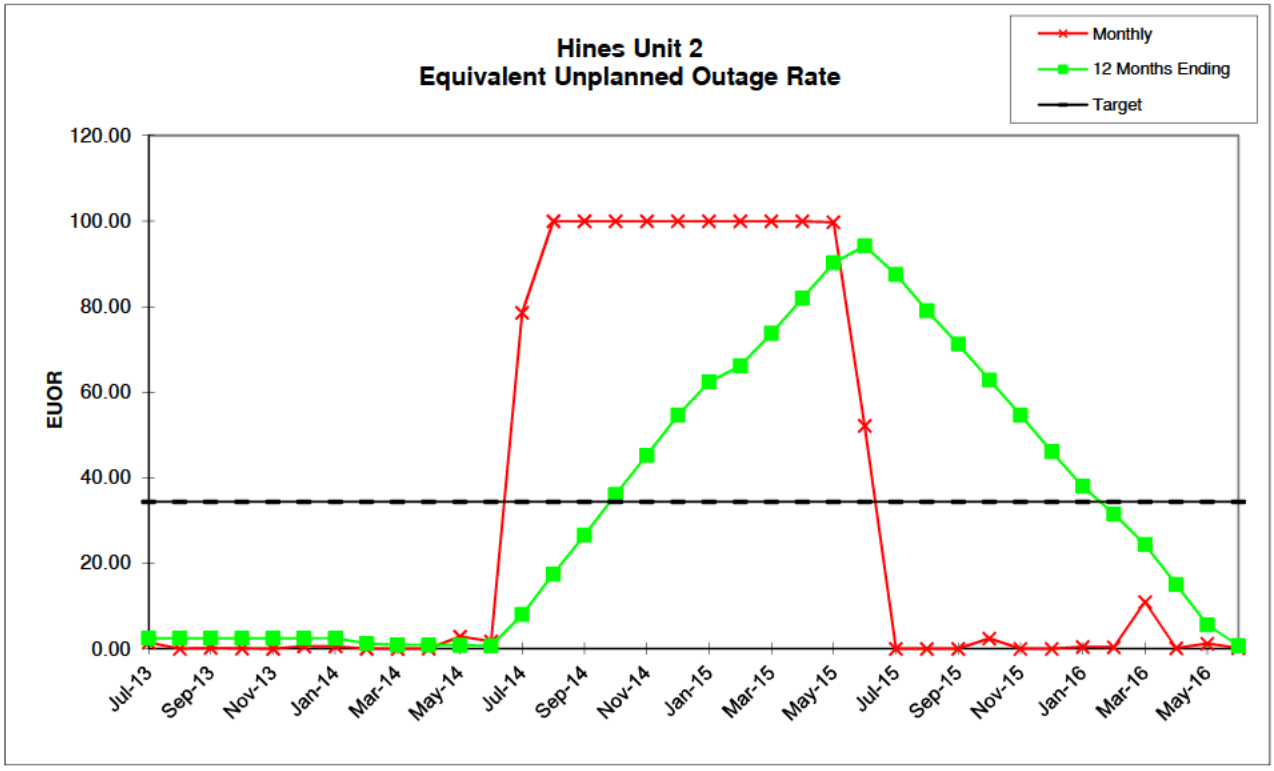
12 MONTHS	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
FOR	62.33	66.09	73.74	81.99	90.24	94.23	87.55	79.06	71.23	62.85	54.61	46.07	37.96	31.46	24.30	15.00	5.45	0.59
MOR	0.31	0.33	0.41	0.60	1.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.07
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.09	0.08	0.07	0.06	0.06	0.05	0.05	0.06
PMOR	0.03	0.03	0.03	0.04	0.08	0.00	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	62.38	66.14	73.78	82.02	90.26	94.23	87.55	79.06	71.23	62.89	54.65	46.11	38.00	31.50	24.35	15.05	5.56	0.72
EUOF	57.48	65.15	73.63	81.85	90.08	94.23	87.55	79.06	70.84	62.55	54.32	45.82	37.36	29.62	21.43	13.25	4.90	0.63
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	2.73	8.73	8.73	8.73	8.73
EAF	42.52	34.85	26.37	18.15	9.92	5.77	12.45	20.94	29.16	37.45	45.68	54.18	62.64	67.65	69.84	78.02	86.37	90.63

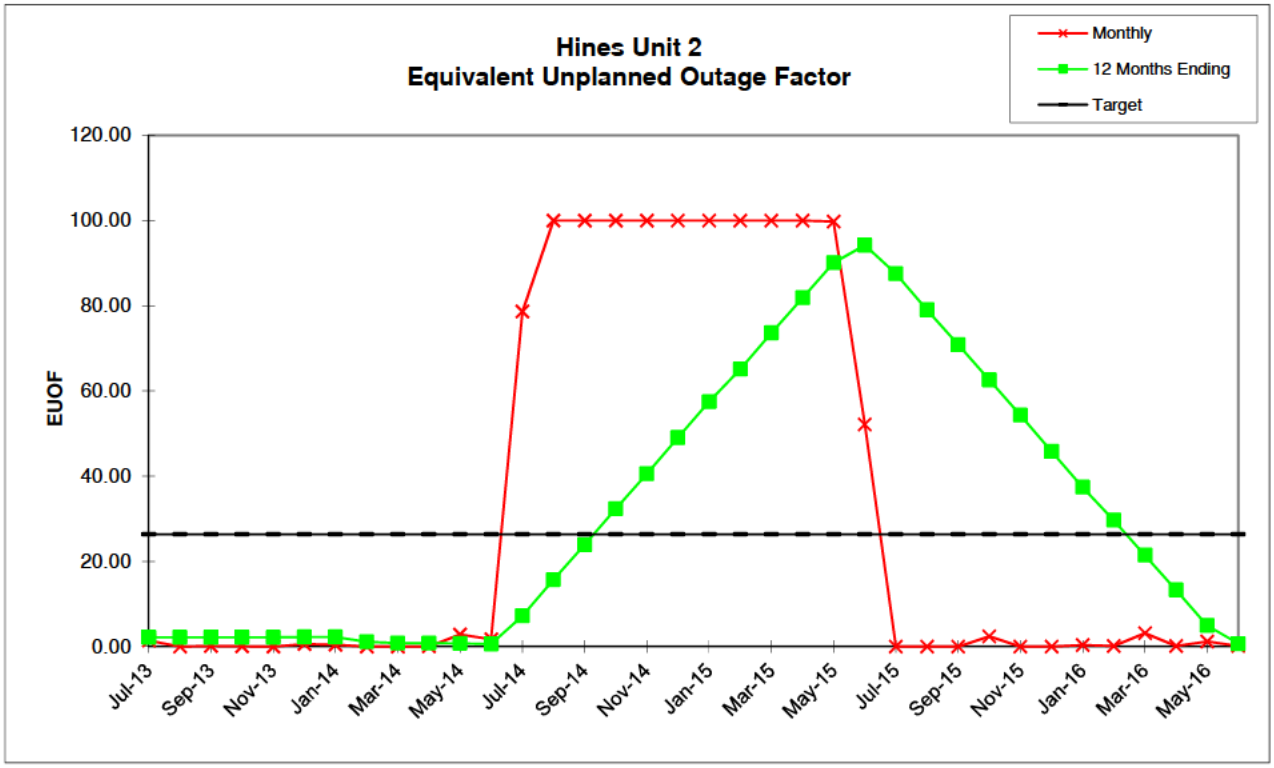

Hines Unit 2
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Hines Unit 2
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Hines Unit 2
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Hines Unit 2
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
0.12
0.10
0.08
0.06
0.04
0.02
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Hines Unit 2
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-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Hines Unit 2
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16

Hines
Unit 3

	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
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	700.42	744.00	720.00	744.00	721.00	664.15	704.47	154.38	119.97	715.08	648.03	720.00	598.19	744.00	560.45	626.35	721.00	545.48
RSH	0.00	0.00	0.00	0.00	0.00	0.00	36.19	409.67	52.74	4.92	3.94	0.00	2.01	0.00	0.00	4.27	0.00	198.52
UH	43.58	0.00	0.00	0.00	0.00	79.85	3.34	107.95	570.29	0.00	92.03	0.00	143.80	0.00	159.54	113.37	0.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	515.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	43.58	0.00	0.00	0.00	0.00	79.85	3.34	1.29	0.00	0.00	92.03	0.00	0.00	0.00	0.00	10.80	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	106.65	55.00	0.00	0.00	0.00	143.80	0.00	159.54	102.57	0.00	0.00
PFOH	17.06	0.00	0.00	2.82	25.78	0.00	0.00	0.00	0.00	0.00	13.80	0.00	0.00	0.00	0.00	2.19	0.00	0.00
LRPF	132.23	0.00	0.00	257.70	381.05	0.00	0.00	0.00	0.00	0.00	88.00	0.00	0.00	0.00	0.00	88.94	0.00	0.00
EFOH	4.62	0.00	0.00	1.49	20.13	0.00	0.00	0.00	0.00	0.00	2.49	0.00	0.00	0.00	0.00	0.40	0.00	0.00
PMOH	0.00	0.00	2.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	156.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	45.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00

MONTHLY	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
FOR	5.86	0.00	0.00	0.00	0.00	10.73	0.47	0.83	0.00	0.00	12.44	0.00	0.00	0.00	0.00	1.70	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.86	31.43	0.00	0.00	0.00	19.38	0.00	22.16	14.07	0.00	0.00
PFOR	0.66	0.00	0.00	0.20	2.79	0.00	0.00	0.00	0.00	0.00	0.38	0.00	0.00	0.00	0.00	0.06	0.00	0.00
PMOR	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	6.48	0.00	0.10	0.20	2.79	10.73	0.47	41.15	31.43	0.00	12.85	0.00	19.38	0.00	22.16	15.38	0.00	0.00
EUOF	6.48	0.00	0.10	0.20	2.79	10.73	0.45	16.06	7.40	0.00	12.79	0.00	19.33	0.00	22.16	15.29	0.00	0.00
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	69.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	93.52	100.00	99.90	99.80	97.21	89.27	99.55	83.94	23.24	100.00	87.21	100.00	80.67	100.00	77.84	84.71	100.00	100.00

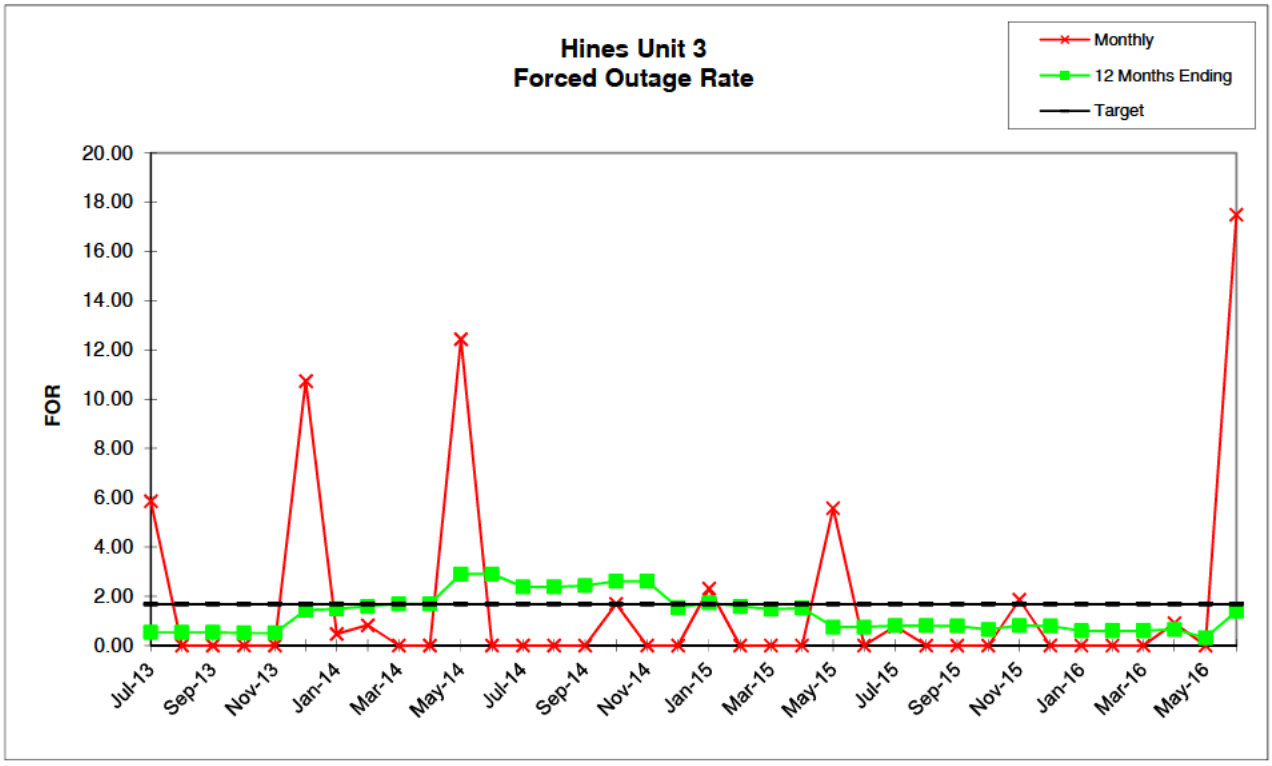
12 MONTHS	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
FOR	0.54	0.54	0.54	0.51	0.51	1.44	1.48	1.59	1.69	1.69	2.91	2.91	2.38	2.38	2.43	2.61	2.61	1.54
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.33	2.12	2.12	2.15	2.15	4.04	4.04	6.15	7.52	7.52	7.64
PFOR	0.29	0.06	0.06	0.07	0.31	0.31	0.31	0.33	0.35	0.35	0.39	0.39	0.33	0.33	0.34	0.33	0.04	0.04
PMOR	0.04	0.04	0.05	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01
EUOR	0.87	0.63	0.64	0.59	0.82	1.75	1.80	3.21	4.09	4.09	5.32	5.32	6.56	6.56	8.61	10.07	9.81	9.01
EUOF	0.80	0.59	0.59	0.58	0.81	1.72	1.75	2.99	3.61	3.61	4.70	4.70	5.79	5.79	7.61	8.89	8.66	7.75
POF	7.54	7.54	7.54	2.33	1.96	1.96	1.96	1.96	5.88	5.88	5.88	5.88	5.88	5.88	5.88	5.88	5.88	5.88
EAF	91.66	91.88	91.87	97.10	97.24	96.32	96.29	95.05	90.50	90.50	89.42	89.42	88.33	88.33	86.51	85.23	85.46	86.37

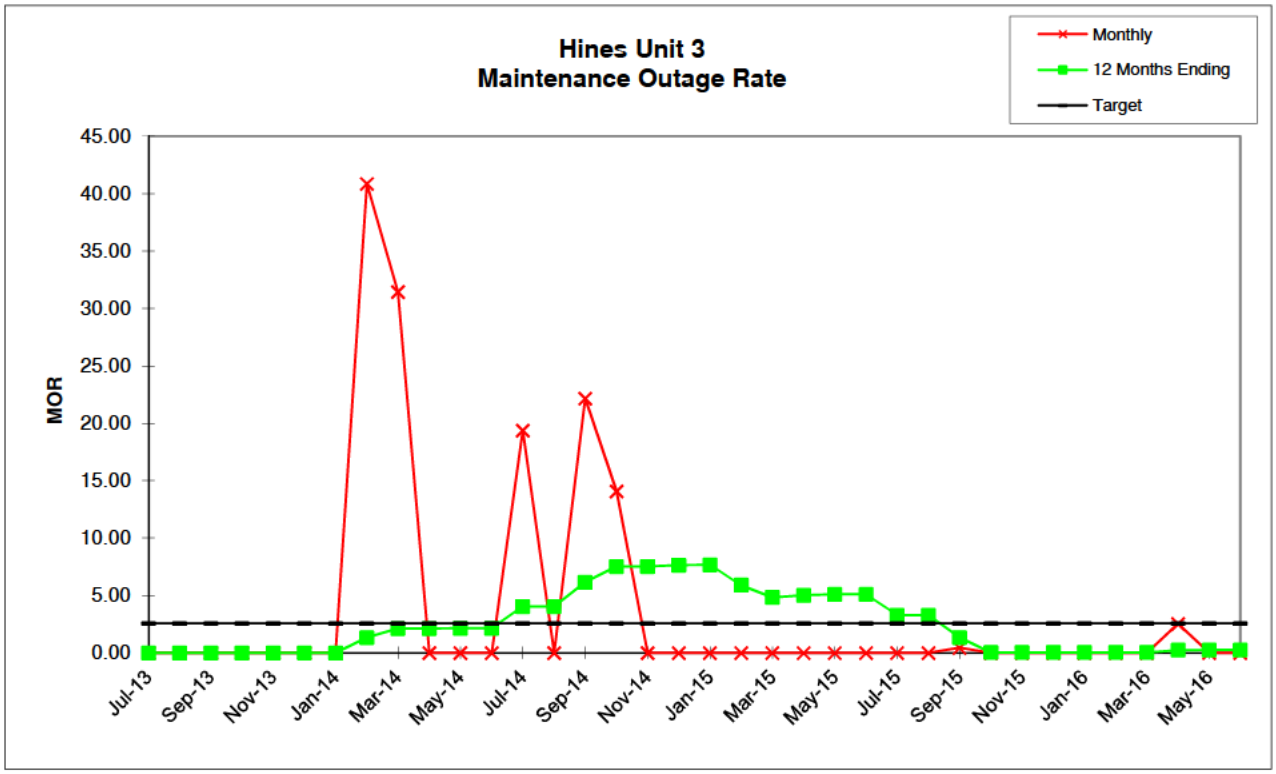
Hines
Unit 3

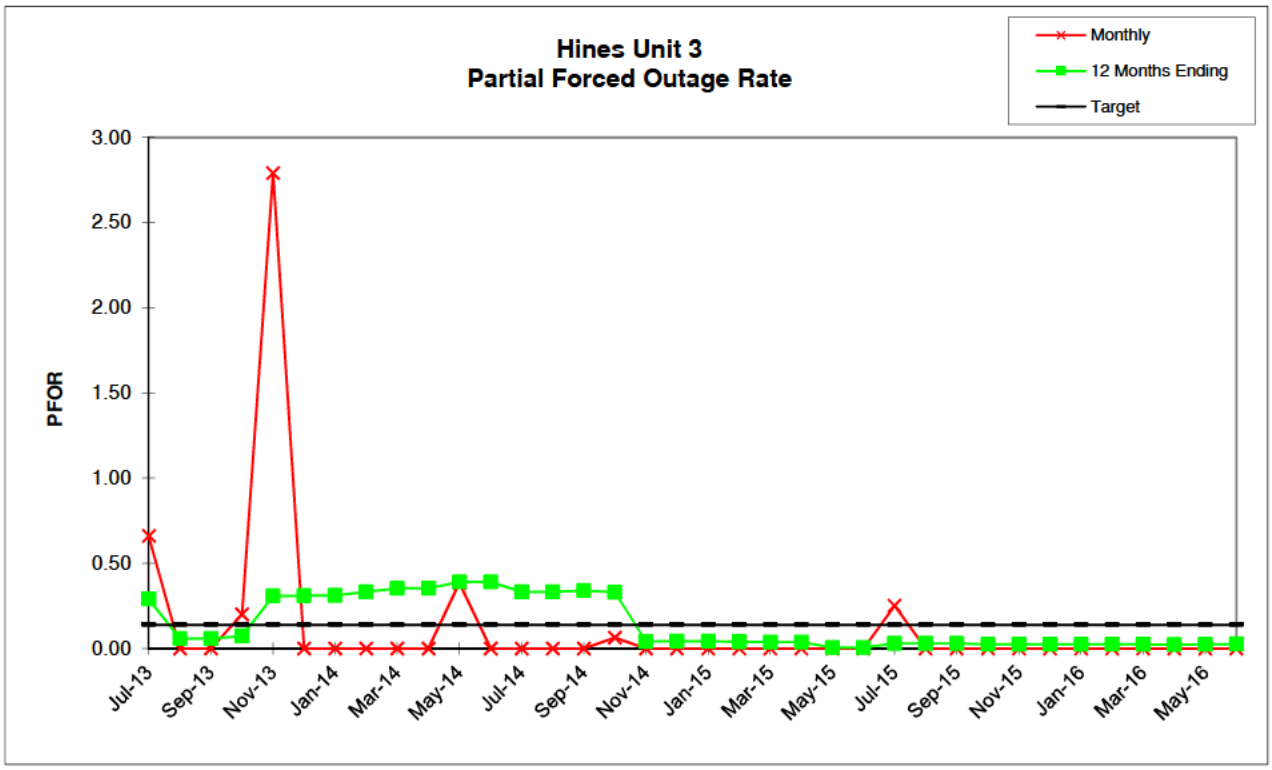
	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	696.00	743.00	720.00	744.00	720.00
SER HOURS	686.93	672.00	743.00	429.71	506.44	720.00	738.24	744.00	710.18	744.00	685.54	686.18	699.56	647.33	700.05	601.01	0.00	373.87
RSH	40.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.64	0.00	22.44	2.13	44.44	48.67	42.95	2.25	0.00	0.89
UH	16.27	0.00	0.00	290.29	237.56	0.00	5.76	0.00	3.18	0.00	13.02	55.69	0.00	0.00	0.00	116.74	744.00	345.24
POH	0.00	0.00	0.00	290.29	207.67	0.00	0.00	0.00	0.00	0.00	0.00	55.69	0.00	0.00	0.00	95.58	744.00	266.02
FOH	16.27	0.00	0.00	0.00	29.89	0.00	5.76	0.00	0.00	0.00	13.02	0.00	0.00	0.00	0.00	5.53	0.00	79.22
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.18	0.00	0.00	0.00	0.00	0.00	0.00	15.62	0.00	0.00
PFOH	0.00	0.00	0.00	0.00	0.00	0.00	14.36	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	63.08	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	1.86	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	0.43	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	41.88	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	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	564.00	564.00	564.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	488.00	544.00	544.00	544.00	544.00	544.00	544.00

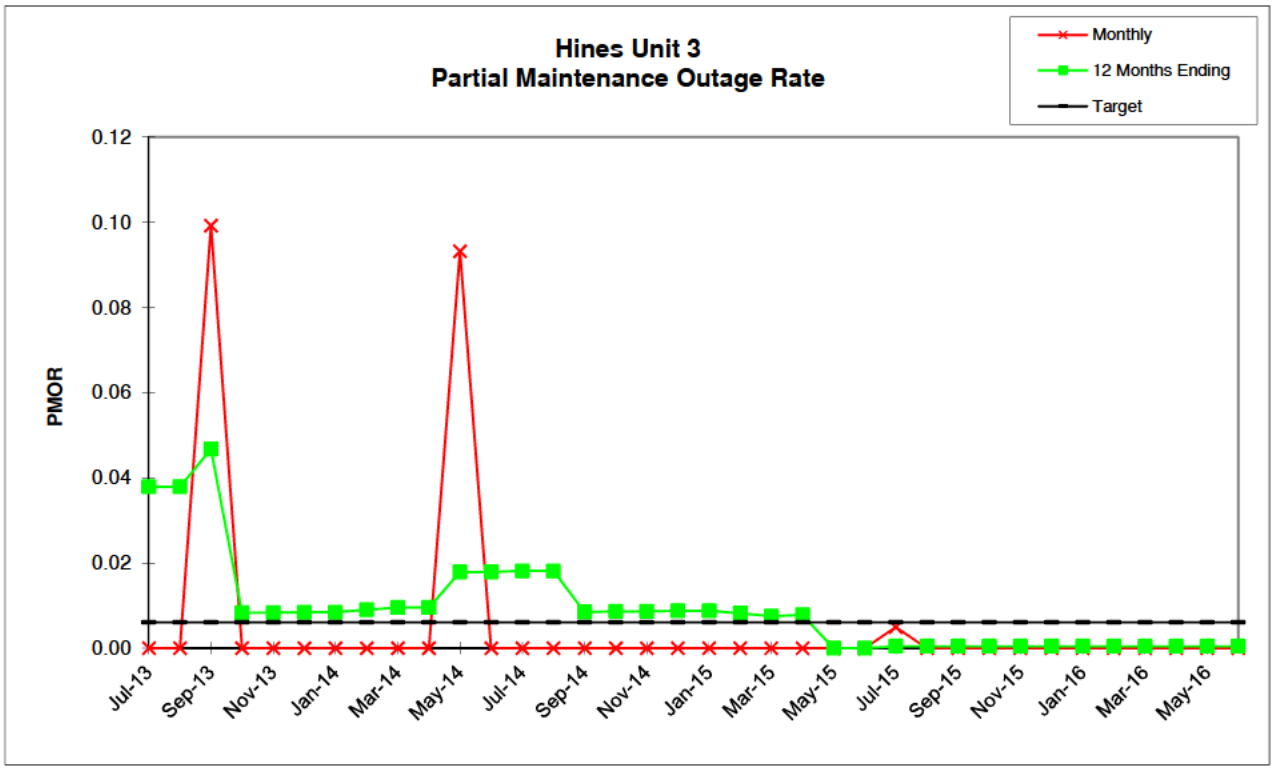
MONTHLY	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**
FOR	2.31	0.00	0.00	0.00	5.57	0.00	0.77	0.00	0.00	0.00	1.86	0.00	0.00	0.00	0.00	0.91	0.00	17.48
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.45	0.00	0.00	0.00	0.00	0.00	0.00	2.53	0.00	0.00
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	2.31	0.00	0.00	0.00	5.57	0.00	1.03	0.00	0.45	0.00	1.86	0.00	0.00	0.00	0.00	3.40	0.00	17.48
EUOF	2.19	0.00	0.00	0.00	4.02	0.00	1.03	0.00	0.44	0.00	1.81	0.00	0.00	0.00	0.00	2.94	0.00	11.00
POF	0.00	0.00	0.00	40.32	27.91	0.00	0.00	0.00	0.00	0.00	0.00	7.49	0.00	0.00	0.00	13.28	100.00	36.95
EAF	97.81	100.00	100.00	59.68	68.07	100.00	98.97	100.00	99.56	100.00	98.19	92.51	100.00	100.00	100.00	83.79	0.00	52.05

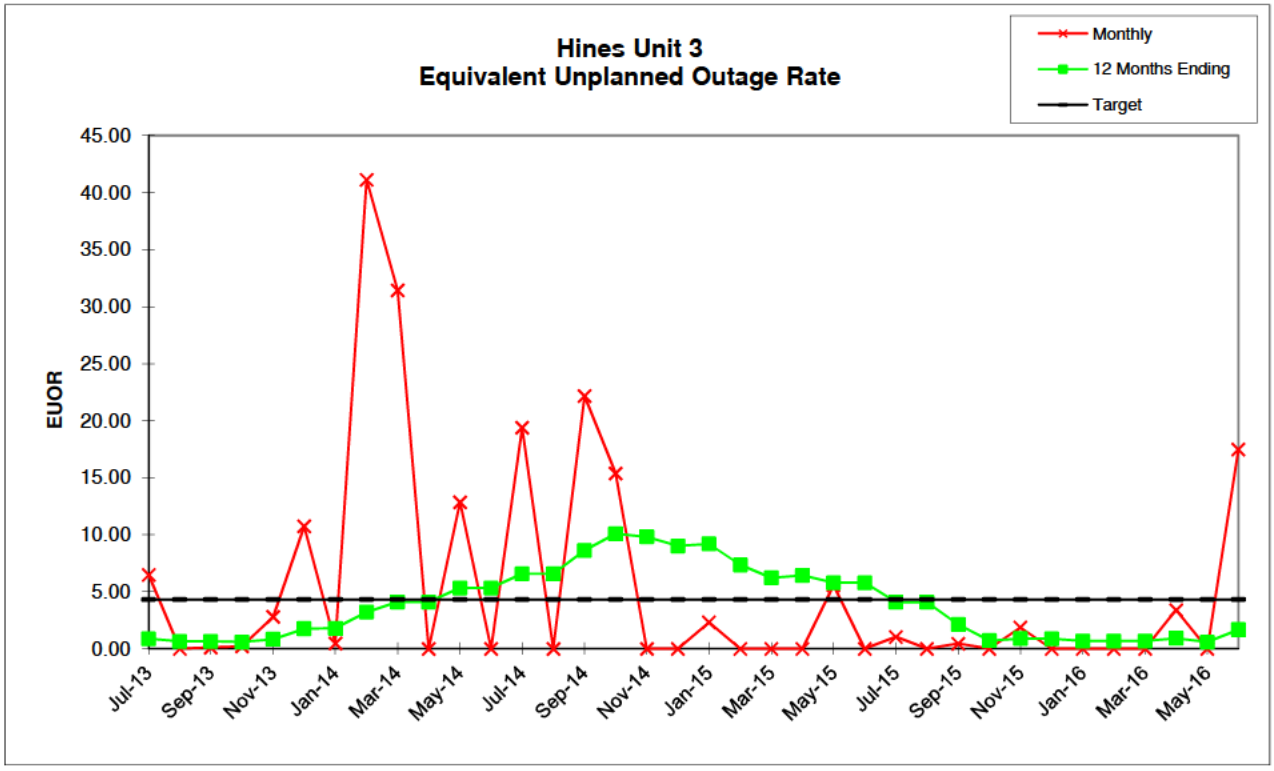
12 MONTHS	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**
FOR	1.73	1.59	1.47	1.52	0.75	0.75	0.81	0.81	0.79	0.65	0.81	0.80	0.60	0.60	0.60	0.66	0.32	1.39
MOR	7.66	5.90	4.84	5.01	5.10	5.10	3.29	3.29	1.33	0.04	0.04	0.04	0.04	0.04	0.04	0.23	0.24	0.26
PFOR	0.04	0.04	0.04	0.04	0.01	0.01	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03
PMOR	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	9.19	7.35	6.21	6.43	5.78	5.78	4.08	4.08	2.13	0.71	0.88	0.86	0.66	0.66	0.67	0.91	0.58	1.67
EUOF	7.89	6.66	6.03	6.03	5.29	5.29	3.73	3.73	1.95	0.65	0.80	0.80	0.61	0.61	0.61	0.85	0.51	1.41
POF	5.88	5.88	0.00	3.31	5.68	5.68	5.68	5.68	5.68	5.68	5.68	6.32	6.32	6.30	6.30	4.09	10.19	13.22
EAF	86.22	87.46	93.97	90.65	89.03	89.03	90.58	90.58	92.37	93.66	93.52	92.88	93.07	93.09	93.09	95.06	89.30	85.37

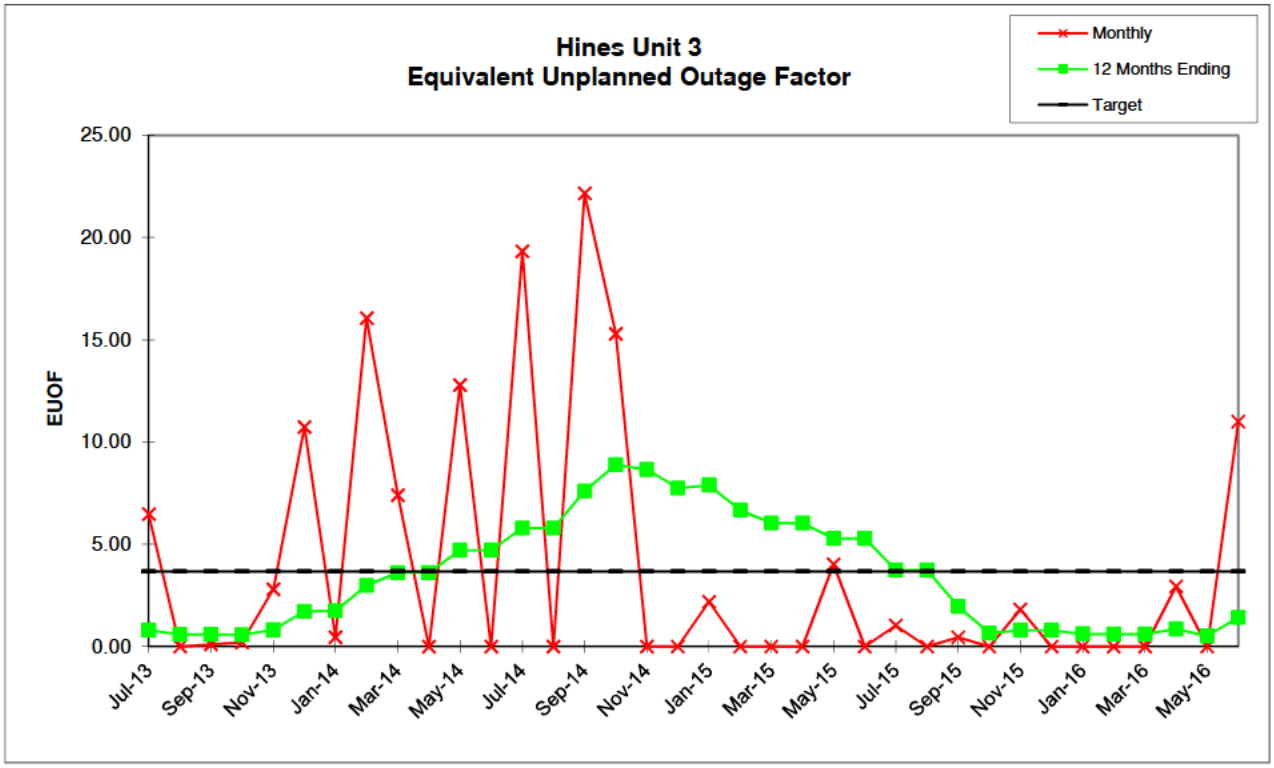

Hines Unit 3
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Hines Unit 3
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Hines Unit 3
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Hines Unit 3
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
0.12
0.10
0.08
0.06
0.04
0.02
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Hines Unit 3
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Hines Unit 3
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
25.00
20.00
15.00
10.00
5.00
0.00
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16

Hines
Unit 4

	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
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	744.00	744.00	716.85	216.02	534.02	744.00	557.95	584.94	743.00	720.00	723.95	715.79	737.02	744.00	694.09	596.00	137.46	543.72
RSH	0.00	0.00	0.00	0.00	0.00	0.00	168.51	87.06	0.00	0.00	0.00	4.21	6.98	0.00	0.38	148.00	230.66	96.50
UH	0.00	0.00	3.15	527.98	186.99	0.00	17.54	0.00	0.00	0.00	20.05	0.00	0.00	0.00	25.53	0.00	352.88	103.78
POH	0.00	0.00	0.00	527.98	182.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	352.88	0.00
FOH	0.00	0.00	3.15	0.00	4.67	0.00	6.34	0.00	0.00	0.00	10.02	0.00	0.00	0.00	12.76	0.00	0.00	51.89
MOH	0.00	0.00	0.00	0.00	0.00	0.00	11.20	0.00	0.00	0.00	10.02	0.00	0.00	0.00	12.76	0.00	0.00	51.89
PFOH	0.00	0.00	0.00	0.00	0.00	0.00	15.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.80	147.88	70.77	59.41
LRPF	0.00	0.00	0.00	0.00	0.00	0.00	79.99	0.00	0.00	0.00	0.00	0.00	0.00	0.00	86.98	84.95	84.74	84.00
EFOH	0.00	0.00	0.00	0.00	0.00	0.00	2.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.73	26.61	12.71	10.57
PMOH	0.00	2.38	1.77	0.00	0.00	0.00	3.96	0.00	0.00	1.17	8.71	0.00	0.00	0.00	14.37	0.00	0.00	0.00
LRPM	0.00	100.14	119.77	0.00	0.00	0.00	80.04	0.00	0.00	37.85	45.01	0.00	0.00	0.00	87.00	0.00	0.00	0.00
EMOH	0.00	0.50	0.45	0.00	0.00	0.00	0.67	0.00	0.00	0.09	0.83	0.00	0.00	0.00	2.65	0.00	0.00	0.00
NPC	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00

MONTHLY	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**
FOR	0.00	0.00	0.44	0.00	0.87	0.00	1.12	0.00	0.00	0.00	1.37	0.00	0.00	0.00	1.81	0.00	0.00	8.71
MOR	0.00	0.00	0.00	0.00	0.00	0.00	1.97	0.00	0.00	0.00	1.37	0.00	0.00	0.00	1.81	0.00	0.00	8.71
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.39	4.47	9.24	1.94
PMOR	0.00	0.07	0.06	0.00	0.00	0.00	0.12	0.00	0.00	0.01	0.11	0.00	0.00	0.00	0.38	0.00	0.00	0.00
EUOR	0.00	0.07	0.50	0.00	0.87	0.00	3.62	0.00	0.00	0.01	2.81	0.00	0.00	0.00	4.29	4.47	9.24	17.66
EUOF	0.00	0.07	0.50	0.00	0.65	0.00	2.80	0.00	0.00	0.01	2.81	0.00	0.00	0.00	4.29	3.58	1.76	15.37
POF	0.00	0.00	0.00	70.97	25.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.94	0.00
EAF	100.00	99.93	99.50	29.03	74.07	100.00	97.20	100.00	100.00	99.99	97.19	100.00	100.00	100.00	95.71	96.42	49.29	84.63

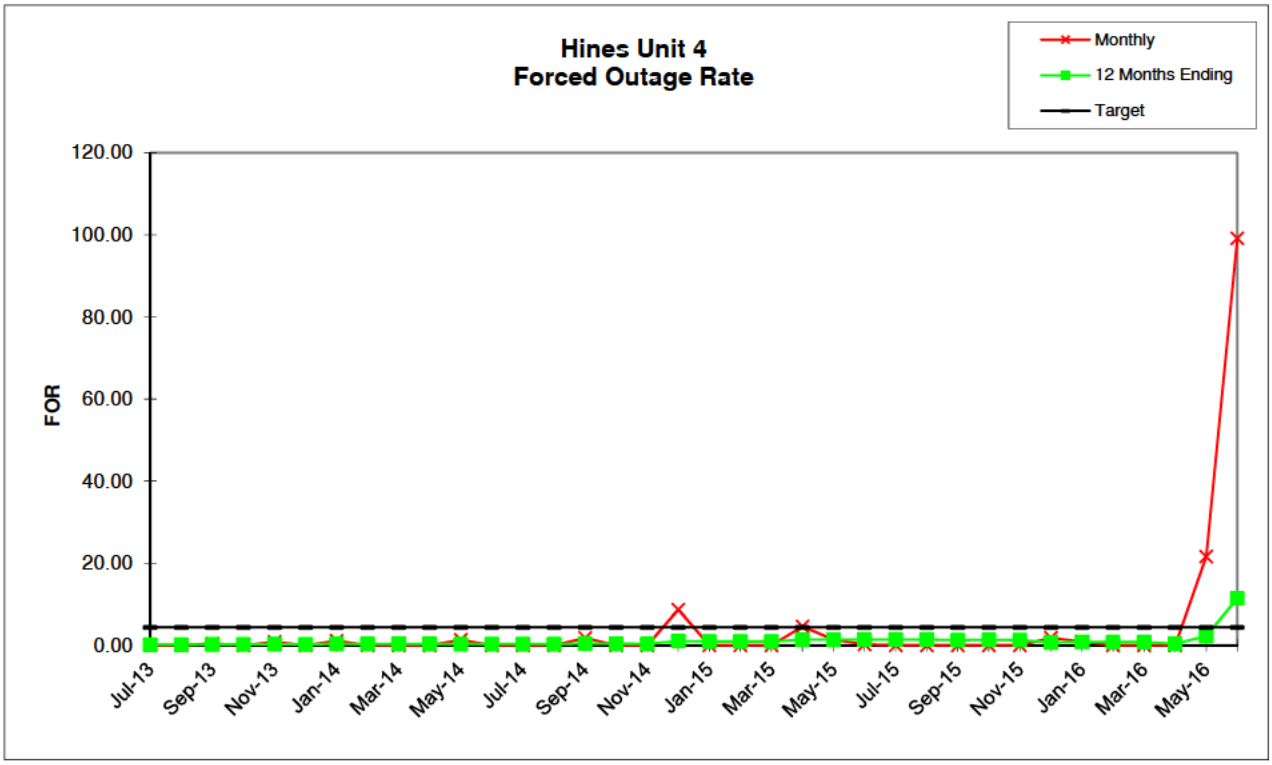
12 MONTHS	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**
FOR	0.18	0.18	0.21	0.23	0.28	0.26	0.35	0.35	0.35	0.35	0.31	0.31	0.31	0.31	0.44	0.42	0.38	1.07
MOR	0.11	0.11	0.11	0.12	0.11	0.11	0.26	0.26	0.14	0.14	0.27	0.27	0.27	0.27	0.44	0.42	0.44	1.13
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.07	0.39	0.58	0.74
PMOR	0.03	0.03	0.03	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.04	0.03	0.03	0.03	0.06	0.05	0.06	0.06
EUOR	0.31	0.32	0.36	0.37	0.41	0.39	0.66	0.67	0.56	0.56	0.66	0.65	0.65	0.64	0.99	1.27	1.44	2.95
EUOF	0.29	0.30	0.34	0.32	0.38	0.36	0.60	0.60	0.49	0.50	0.58	0.58	0.58	0.57	0.88	1.19	1.28	2.58
POF	5.24	5.24	5.24	11.27	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11	8.11	2.08	4.03	4.03
EAF	94.46	94.46	94.42	88.41	91.51	91.53	91.29	91.29	91.40	91.40	91.31	91.31	91.31	91.32	91.01	96.73	94.69	93.39

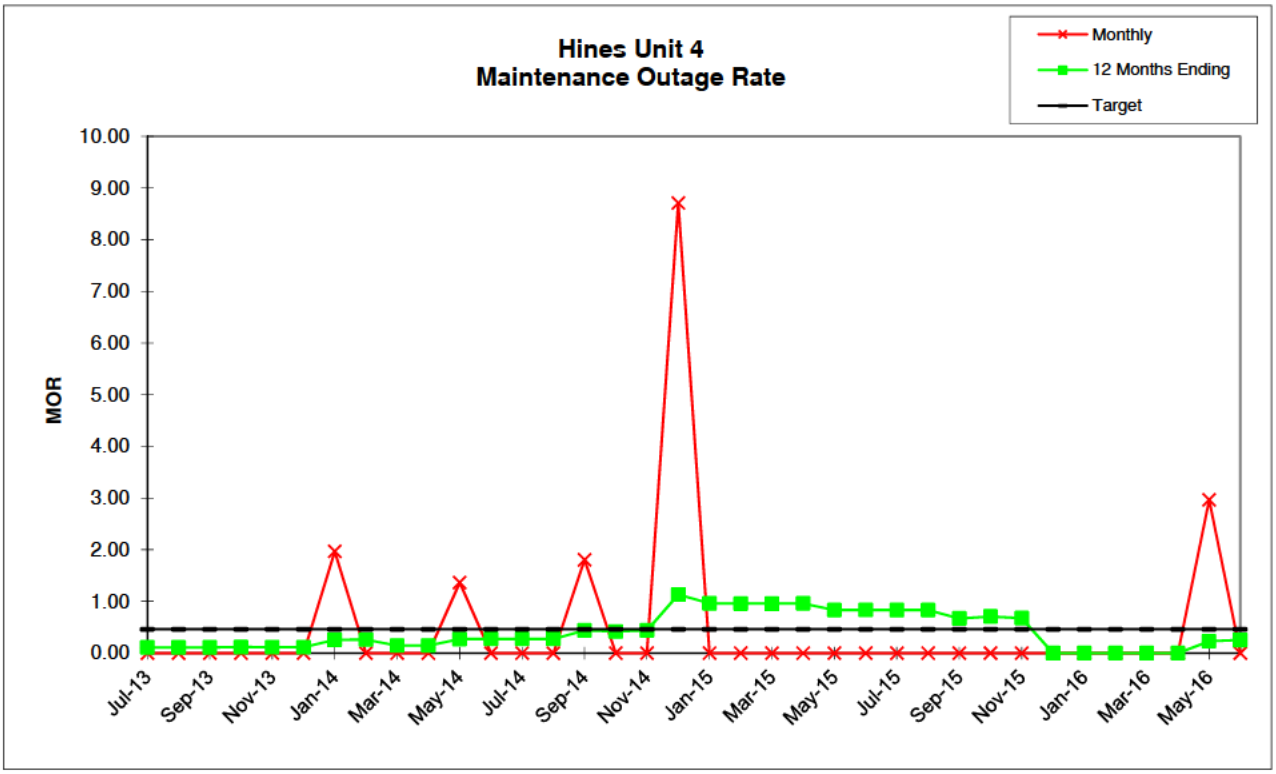
Hines
Unit 4

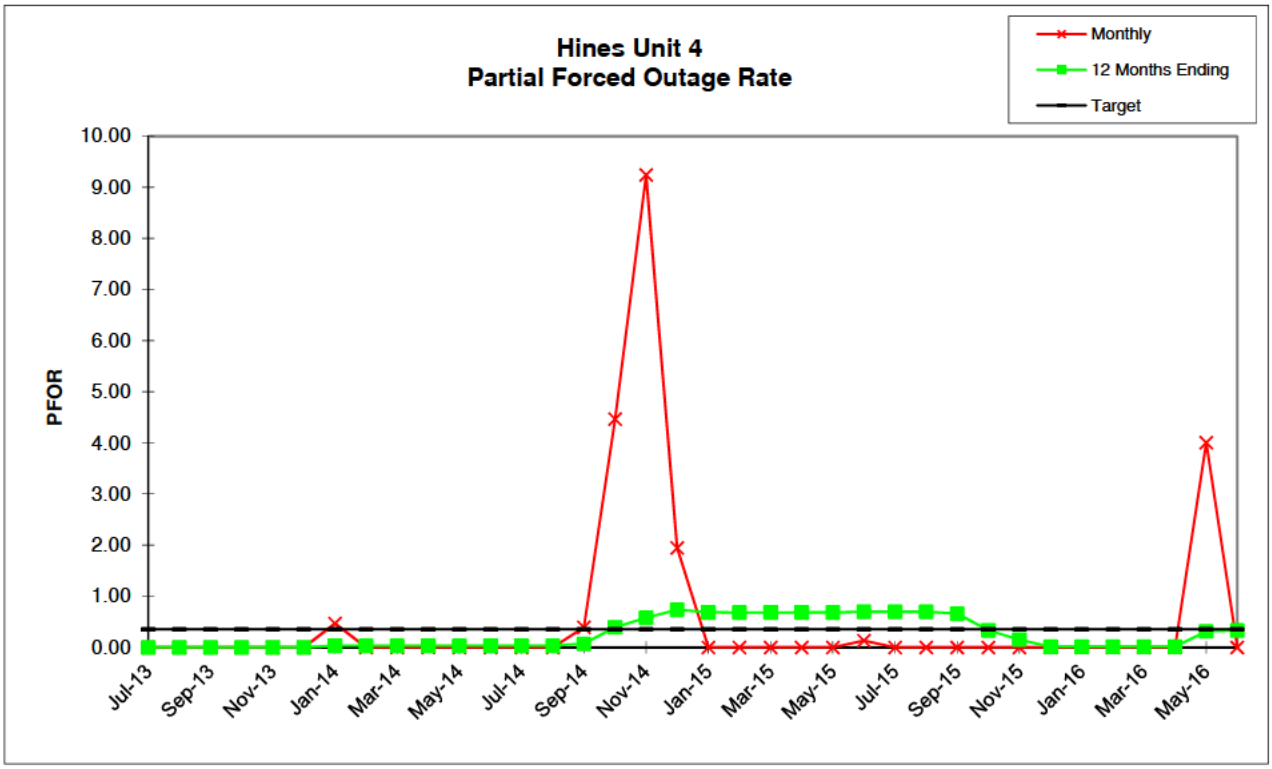
	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
PER HOURS	744.00	672.00	743.00	720.00	744.00	720.00	744.00	744.00	720.00	744.00	721.00	744.00	744.00	696.00	743.00	720.00	744.00	720.00
SER HOURS	732.40	639.19	743.00	686.86	733.43	698.02	744.00	744.00	692.25	188.05	479.78	564.85	713.48	696.00	743.00	720.00	569.39	6.08
RSH	11.60	32.81	0.00	0.00	0.00	20.30	0.00	0.00	27.75	0.00	10.56	19.62	23.97	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	0.00	33.14	10.56	1.68	0.00	0.00	0.00	555.95	230.66	159.53	6.55	0.00	0.00	0.00	174.61	713.91
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	555.95	230.66	148.82	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	33.14	10.56	1.68	0.00	0.00	0.00	0.00	0.00	10.71	6.55	0.00	0.00	0.00	157.21	713.91
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.40	0.00
PFOH	0.00	0.00	0.00	0.00	0.00	9.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	203.75	0.00
LRPF	0.00	0.00	0.00	0.00	0.00	43.96	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	59.13	0.00
EFOH	0.00	0.00	0.00	0.00	0.00	0.93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.82	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	544.00	544.00	544.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	472.00	528.00	528.00	528.00	528.00	528.00	528.00

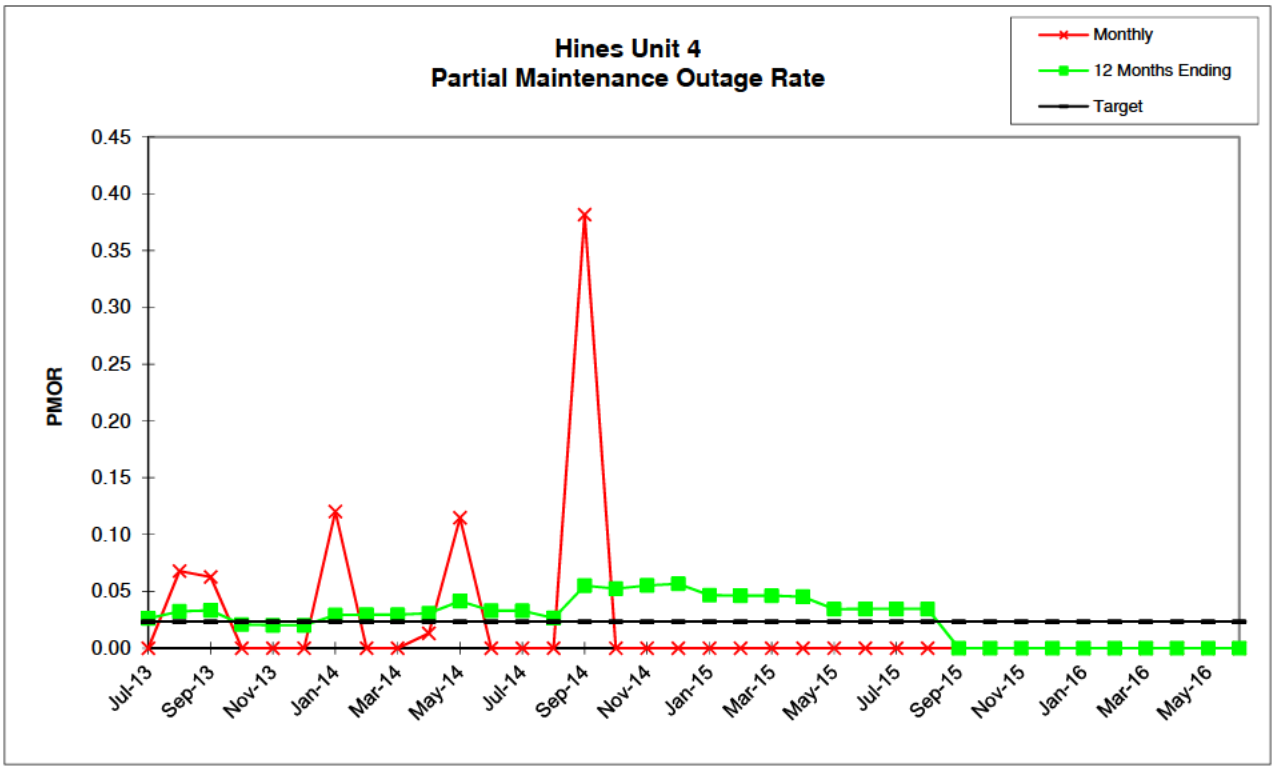
MONTHLY	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**
FOR	0.00	0.00	0.00	4.60	1.42	0.24	0.00	0.00	0.00	0.00	0.00	1.86	0.91	0.00	0.00	0.00	21.64	99.16
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.97	0.00
PFOR	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	0.00	0.00	0.00	4.01	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	0.00	0.00	0.00	4.60	1.42	0.37	0.00	0.00	0.00	0.00	0.00	1.86	0.91	0.00	0.00	0.00	26.54	99.16
EUOF	0.00	0.00	0.00	4.60	1.42	0.36	0.00	0.00	0.00	0.00	0.00	1.44	0.88	0.00	0.00	0.00	26.54	99.15
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	74.72	31.99	20.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	100.00	100.00	100.00	95.40	98.58	99.64	100.00	100.00	100.00	25.28	68.01	78.56	99.12	100.00	100.00	100.00	73.46	0.85

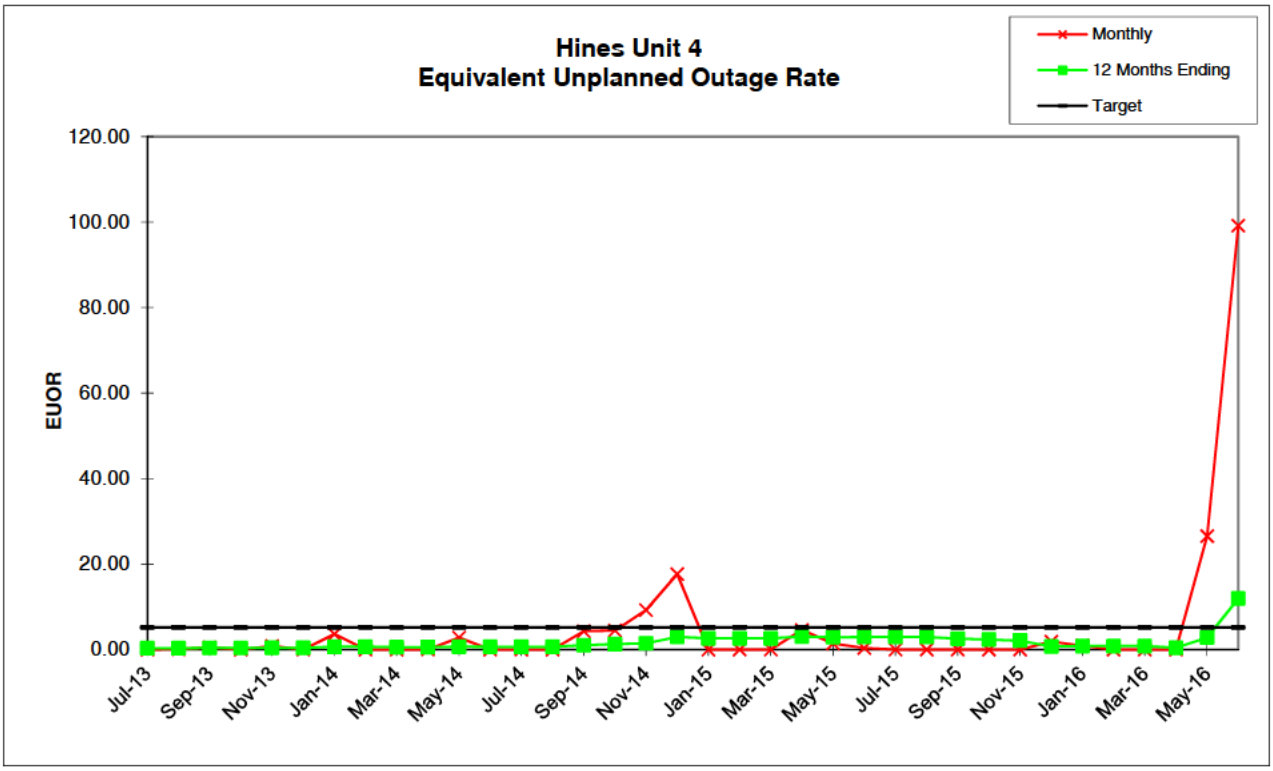
12 MONTHS	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**
FOR	0.96	0.96	0.96	1.38	1.39	1.41	1.41	1.41	1.25	1.32	1.26	0.73	0.81	0.81	0.81	0.38	2.28	11.46
MOR	0.96	0.96	0.96	0.96	0.83	0.83	0.83	0.83	0.67	0.71	0.68	0.00	0.00	0.00	0.00	0.00	0.23	0.25
PFOR	0.69	0.68	0.68	0.68	0.68	0.70	0.70	0.70	0.66	0.33	0.15	0.01	0.01	0.01	0.01	0.01	0.31	0.33
PMOR	0.05	0.05	0.05	0.05	0.03	0.03	0.03	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	2.63	2.61	2.61	3.03	2.90	2.94	2.93	2.93	2.55	2.33	2.07	0.74	0.83	0.82	0.82	0.39	2.81	11.96
EUOF	2.35	2.35	2.35	2.72	2.61	2.64	2.64	2.64	2.28	1.98	1.83	0.65	0.73	0.72	0.72	0.35	2.47	10.57
POF	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	10.37	8.98	10.68	10.68	10.65	10.65	10.65	10.65	10.65
EAF	93.63	93.63	93.63	93.25	93.37	93.34	93.34	93.34	93.69	87.65	89.19	88.67	88.60	88.63	88.63	89.00	86.88	78.78

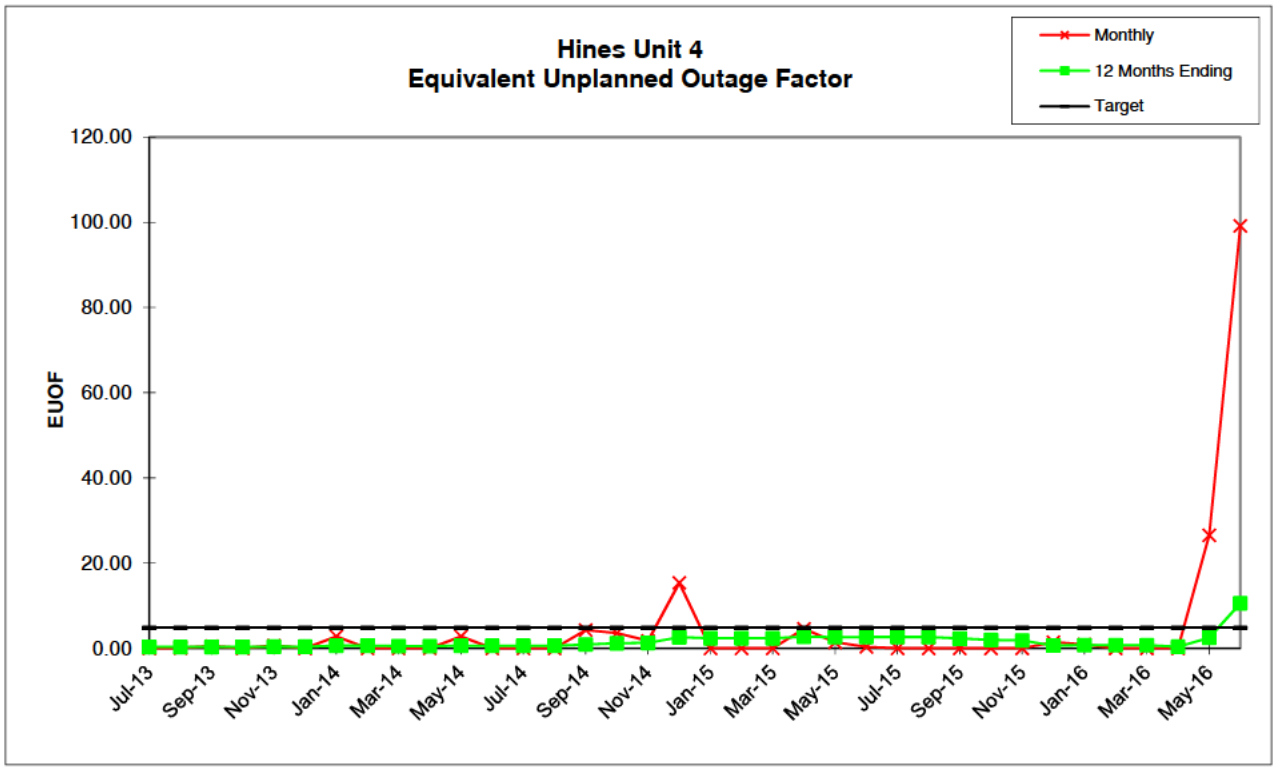

Hines Unit 4
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
120.00
100.00
80.00
60.00
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Jul-13
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Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Hines Unit 4
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
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Jul-13
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May-15
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Nov-15
Jan-16
Mar-16
May-16


Hines Unit 4
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
10.00
9.00
8.00
7.00
6.00
5.00
4.00
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Jul-13
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Sep-15
Nov-15
Jan-16
Mar-16
May-16


Hines Unit 4
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
0.45
0.40
0.35
0.30
0.25
0.20
0.15
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Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


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-13
Sep-13
Nov-13
Jan-14
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May-14
Jul-14
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Nov-14
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May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16


Hines Unit 4
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jul-13
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Nov-15
Jan-16
Mar-16
May-16

Duke Energy Florida
ISFSI

Docket No. 160001
Witness: Olivier
Exhibit No. ___(MO-1)

2016	Act Jan	Act Feb	Act Mar	Act Apr	Act May	Act Jun	Est Jul	Est Aug	Est Sep	Est Oct	Est Nov	Est Dec	Total
Beginning Bal.	$60,807,783	$66,105,667	$68,315,826	$71,359,419	$73,227,263	$74,660,565	$77,788,491	$81,343,812	$85,892,041	$88,940,390	$93,078,805	$97,529,906	$60,807,783
Expenditures [1]	4,989,755	1,883,801	2,704,480	1,516,807	1,074,250	2,757,801	3,168,968	4,142,203	2,623,880	3,696,497	3,988,329	5,175,915	37,722,685
AFUDC [2]	308,129	326,357	339,113	351,037	359,052	370,126	386,352	406,026	424,470	441,918	462,772	487,329	4,662,682
Ending Bal.	$66,105,667	$68,315,826	$71,359,419	$73,227,263	$74,660,565	$77,788,491	$81,343,812	$85,892,041	$88,940,390	$93,078,805	$97,529,906	$103,193,150	$103,193,150

2017	Est Jan	Est Feb	Est Mar	Est Apr	Est May	Est Jun	Est [4] Jul	Est Aug	Est Sep	Est Oct	Est Nov	Est Dec	Total
Beginning Bal.	$103,193,150	$107,832,736	$112,513,551	$119,978,346	$124,429,207	$126,464,992	$128,104,329	$129,059,972	$130,317,415	$130,568,049	$130,653,300	$130,738,550	$103,193,150
Expenditures [1]	4,127,243	4,145,844	6,900,336	3,857,472	1,426,648	1,021,277	955,643	1,257,444	250,634	85,250	85,250	127,876	24,240,916
AFUDC [2]	512,343	534,971	564,459	593,389	609,138	618,060							3,432,360
Ending Bal.	107,832,736	112,513,551	119,978,346	124,429,207	126,464,992	128,104,329	129,059,972	130,317,415	130,568,049	130,653,300	130,738,550	130,866,426	130,866,426
Average Bal.							128,582,151	129,688,694	130,442,732	130,610,675	130,695,925	130,802,488	
ROR [3]							8.12%	8.12%	8.12%	8.12%	8.12%	8.12%	
Revenue Requirement							$870,073	$877,560	$882,662	$883,799	$884,376	$885,097	$5,283,567

Notes:

[1] Expenditures represent retail portion after removing co-owner portion (8.2194%) and multiplying remaining amount by retail separation factor of 92.885% from 2013 RRSSA Exhibit 1 (Order PSC-13-0598).

[2] Monthly AFUDC rate is .48676%, based on annual rate of 6% in RRSSA Exhibits 3 & 10 (Order PSC-13-0598), discounted per AFUDC Rule 25-6.0141(3)(a). AFUDC is calculated on average monthly balance before AFUDC.

[3] Rate of Return is based on 2013 RRSSA Exhibit 10 (Order PSC-13-0598). This rate is divided by 12 when calculating the revenue requirement on the following line.

[4] Estimated construction completion date is June 30, 2017. Therefore, AFUDC ceases and CCR return commences July 1, 2017.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 14
PARTY: DUKE ENERGY FLORIDA, LLC – (DIRECT)
DESCRIPTION: Marcia Olivier MO-1

Duke Energy Florida
Batch 19 Fuel Sale

REDACTED

Docket No. 160001
Witness: Olivier
Exhibit No. ___(MO-2)

2016	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Beginning Bal. [1]	[redacted]												
Cash Receipts [1]													
Ending Bal.													
Average Bal.													
Revenue Require [2]													

2017	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Beginning Bal. [1]	[redacted]												
Cash Receipts [1]													
Ending Bal.													
Average Bal.													
Revenue Require [2]													

[1] Amounts are consistent with Exhibit __(MO-5) attached to the direct testimony of Marcia Olivier in Docket No. 150148 on May 22, 2015.
[2] Revenue Requirement is based on 8.12% carrying charge annual rate in RRSSA Exhibit 10, approved in Order No. PSC-13-0598-FOF-EI.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 15
PARTY: DUKE ENERGY FLORIDA, LLC – (DIRECT)
DESCRIPTION: Marcia Olivier MO-2

Duke Energy Florida
RRSSA Second Amendment

Docket No. 160001
Witness: Olivier
Exhibit No. ___(MO-3)

REDACTED

2016													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Beginning Bal.	[redacted]												
Carrying Charge [1]													
Ending Bal.													

2017													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Beginning Bal.	[redacted]												
Amortization													
Ending Bal.													
Average Bal.													
Carrying Charge [2]													
Revenue Require													

[1] Carrying Charge is based on 6% annual rate in RRSSA Exhibit 10, approved in Order No. PSC-13-0598-FOF-EI, discounted to monthly rate of .48676% per AFUDC Rule 25-6.0141(3)(a), F.A.C.

[2] Carrying Charge is based on 3% annual rate approved in Order No. PSC-16-0138-FOF-EI.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 16
PARTY: DUKE ENERGY FLORIDA, LLC – (DIRECT)
DESCRIPTION: Marcia Olivier MO-3

Docket 160001-EI
Exhibit No. ____(CAM-3)
Part 1

DUKE ENERGY FLORIDA

FUEL AND CAPACITY COST RECOVERY FACTOR

JANUARY THROUGH DECEMBER 2017

PART 1 – 2017 FUEL PRICE FORECAST ASSUMPTIONS

Projected Market Price by Fuel Type

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 17
PARTY: DUKE ENERGY FLORIDA, LLC – (DIRECT)
DESCRIPTION: Marcia Olivier CAM-3

PROJECTED MARKET PRICE BY FUEL TYPE

	Light Oil		Coal Crystal River 1 & 2		Coal Crystal River 4 & 5		Natural Gas
Month	**$/barrel**	**$/mmbtu**	**$/ton**	**$/mmbtu**	**$/ton**	**$/mmbtu**	**$/mmbtu**
Jan 2017	60.06	10.36	90.13	3.82	69.78	3.07	3.04
Feb 2017	60.74	10.48	90.13	3.82	68.42	3.01	3.04
Mar 2017	61.33	10.58	90.13	3.82	66.33	2.92	2.99
Apr 2017	61.39	10.59	90.13	3.82	65.11	2.87	2.80
May 2017	61.76	10.66	90.25	3.82	63.93	2.82	2.79
Jun 2017	62.24	10.74	91.27	3.87	63.01	2.78	2.82
Jul 2017	62.49	10.78	92.14	3.92	62.02	2.74	2.86
Aug 2017	62.96	10.86	92.80	3.95	61.29	2.71	2.87
Sep 2017	63.36	10.93	93.25	3.97	60.78	2.69	2.86
Oct 2017	63.64	10.98	93.39	3.98	60.59	2.68	2.89
Nov 2017	63.33	10.93	93.40	3.98	60.54	2.68	2.96
Dec 2017	62.66	10.81	93.40	3.98	60.23	2.66	3.10
Average	62.16	10.73	91.70	3.90	63.50	2.80	2.92

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 current hedge positions and transportation costs.

Coal: Coal price projections are based on the current coal supply, transportation agreements, and forecasted deliveries. It assumes environmental restrictions on coal quality remain in effect as per current permits: 2.1 lbs. per million BTU sulfur dioxide limit for Crystal River Units 1 and 2. Crystal River 4 and 5 have operating scrubbers which allow for consideration of higher sulfur coal.

Natural Gas: The base market natural gas price forecast is the NYMEX Henry Hub forwards. This table includes natural gas market commodity prices only; however, the fuel forecast incorporates hedges and transportation costs. Forecast prices are based on expected contract specifications and incorporate current hedge positions. Firm transportation costs for Florida Gas Transmission and Gulfstream pipeline are based on expected tariff rates and/or negotiated rates. Interruptible transportation rates and availability are based on expected tariff rates and market conditions.

Docket 160001-EI
Exhibit No. ____(CAM-3)
Part 2

DUKE ENERGY FLORIDA

FUEL COST RECOVERY

JANUARY THROUGH DECEMBER 2017

PART 2 - 2017 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

Docket No. 160001-EI
Schedule E1
Exhibit CAM-3, Part 2

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January through December 2017

			DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)		1,221,838,538	37,020,131	3.3005
2.	Spent Nuclear Fuel Disposal Cost		0	0 *	0.0000
3.	Coal Car Investment		0	0	0.0000
4.	Adjustment to Fuel Cost		0	0	0.0000
5.	TOTAL COST OF GENERATED POWER		1,221,838,538	37,020,131	3.3005
6.	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)		73,811,326	1,760,693	4.1922
7.	Energy Cost of Economy Purchases (E9)		4,417,649	97,274	4.5415
8.	Payments to Qualifying Facilities (E8)		140,596,014	3,329,832	4.2223
9.	TOTAL COST OF PURCHASED POWER		218,824,989	5,187,798	4.2181
10.	TOTAL AVAILABLE MWH			42,207,929	
11.	Fuel Cost of Economy Sales	(E6)	(2,516,281)	(82,705)	3.0425
11a.	Gain on Economy Sales	(E6)	(612,488)	(82,705) *	0.7406
12.	Fuel Cost of Stratified Sales	(E6)	(23,804,974)	(956,306)	2.4893
13.	TOTAL FUEL COST AND GAINS ON POWER SALES		(26,933,743)	(1,039,011)	2.5922
14.	Net Inadvertent Interchange				
15.	TOTAL FUEL AND NET POWER TRANSACTIONS		1,413,729,784	41,168,918	3.4340
16.	Net Unbilled		(15,998,686) *	465,894	(0.0406)
17.	Company Use		5,357,002 *	(156,000)	0.0136
18.	T & D Losses		70,545,065 *	(2,054,328)	0.1789
19.	Adjusted System Sales		1,413,729,784	39,424,485	3.5859
20.	Wholesale Sales (Excluding Supplemental Sales)		(7,543,808)	(210,449)	3.5846
21.	Jurisdictional Sales		1,406,185,977	39,214,036	3.5859
22.	Jurisdictional Sales Adjusted for Line Losses x	1.0004	1,406,748,451	39,214,036	3.5874
23.	Prior Period True-Up (Sch E1-A)		26,217,663	39,214,036	0.0669
24.	Total Jurisdictional Fuel Cost		1,432,966,114	39,214,036	3.6542
25.	Revenue Tax Factor		1,031,736		1.0007
26.	Fuel Cost Adjusted for Taxes		1,433,997,850	39,214,036	3.6568
27.	GPIF **		2,255,421	39,214,036	0.0058
28.	Fuel Factor Adjusted for taxes including GPIF		1,436,253,271	39,214,036	3.6626
29.	Total Fuel Cost Factor (rounded to the nearest .001 cents/ KWH)				3.663

* For Informational Purposes Only

** Based on Jurisdictional Sales

Duke Energy Florida
Calculation of Total True-Up
(Projected Period)
Estimated for the Period of : January through December 2017

1.	Actual Over/(Under) Recovery January - December 2015. **(** Schedule E1-B, Page 2 of 2, Section C, Line 9 - Dec '15 **)**	$	116,563,080
2.	Midcourse (Over)/Under Recovery January - December 2015 . (Refunded)/Collected January - December 2016. **(** Schedule E1-B, Page 2 of 2, Section C, Line 10 - Dec '15 **)**	$	(116,588,896)
3.	Estimated Over/(Under) Recovery January - December 2016 **(** Schedule E1-B, Page 2 of 2, Section C, Lines 8 and 12 - Dec '16 **)**	$	(26,191,847)
4.	Total Over/(Under) Recovery to be Included in the January - December 2017 Projected Period **(** Lines 1 through 3 **)**	$	(26,217,663)
5.	Jurisdictional mWh Sales (Projected Period)	mWh	39,214,036
6.	True-Up Factor (Line 4 / Line 5)	Cents/kWh	0.067

CALCULATION OF ESTIMATED TRUE-UP
(6 MONTHS ACTUAL, 6 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2016

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 94,981,804	$ 83,413,721	$ 78,345,839	$ 82,817,723	$ 90,802,680	$ 110,507,482	$ 540,869,249
	2	Fuel Cost of Power Sold	(2,691,656)	(1,345,614)	(1,423,831)	(2,132,788)	(1,895,385)	(4,198,390)	(13,687,665)
	3	Fuel Cost of Purchased Power	4,937,035	6,217,173	14,421,739	20,084,233	32,818,134	31,608,698	110,087,011
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	8,284,310	9,432,944	9,730,163	7,658,173	10,499,028	10,232,952	55,837,571
	4	Energy Cost of Economy Purchases	216,014	(55,757)	265,606	390,715	406,645	1,004,737	2,227,961
	5	Adjustments to Fuel Cost	(24,885)	(26,759)	(31,140)	(30,128)	32,448	(21,508)	(101,972)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	105,702,622	97,635,708	101,308,376	108,787,927	132,663,550	149,133,972	695,232,155
B	1	Jurisdictional MWH Sales	2,772,355	2,712,018	2,687,916	2,710,583	3,189,901	3,609,509	17,682,282
	2	Non-Jurisdictional MWH Sales	30,873	20,634	21,753	74,556	23,060	28,457	199,333
	3	TOTAL SALES (Lines B1 + B2)	2,803,228	2,732,653	2,709,669	2,785,139	3,212,961	3,637,966	17,881,616
	4	Jurisdictional % of Total Sales (Line B1/B3)	98.90%	99.24%	99.20%	97.32%	99.28%	99.22%	98.89%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	98,935,994	97,150,007	94,743,489	78,832,246	94,121,778	108,162,345	571,945,858
	1a	RRSSA Refund - $60M	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	30,000,000
	1b	RRSSA Fuel Adjustment	-	-	-	-	-	-	-
	1c	RRSSA Refund - $10M	833,333	833,333	833,333	833,333	833,333	833,333	5,000,000
	2	True-Up Provision	6,560,919	6,560,919	6,560,919	10,764,480	10,764,480	10,764,480	51,976,199
	2a	Incentive Provision	717,816	717,816	717,816	717,816	717,816	717,816	4,306,896
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	112,048,062	110,262,076	107,855,558	96,147,876	111,437,408	125,477,974	663,228,953
	4	Fuel & Net Power Transactions (Line A6)	105,702,622	97,635,708	101,308,376	108,787,927	132,663,550	149,133,972	695,232,155
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	104,594,254	96,944,061	100,538,108	105,914,760	131,761,056	148,029,915	687,782,154
	6	Over/(Under) Recovery (Line C3 - Line C5)	7,453,809	13,318,014	7,317,449	(9,766,884)	(20,323,648)	(22,551,941)	(24,553,201)
	7	Interest Provision	38,614	41,097	44,882	37,893	25,826	17,633	205,945
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	7,492,423	13,359,111	7,362,331	(9,728,990)	(20,297,822)	(22,534,308)	(24,347,255)
	9	Plus: Prior Period Balance	116,563,080	116,563,080	116,563,080	116,563,080	116,563,080	116,563,080	116,563,080
	10	Plus: Cumulative True-Up Provision	(6,560,919)	(13,121,839)	(19,682,758)	(30,447,238)	(41,211,719)	(51,976,199)	(51,976,199)
	11	Subtotal Prior Period True-up	110,002,161	103,441,241	96,880,322	86,115,842	75,351,361	64,586,881	64,586,881
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	$117,494,583	124,292,775	$125,094,187	$104,600,716	$73,538,414	$40,239,626	40,239,626

CALCULATION OF ESTIMATED TRUE-UP
(6 MONTHS ACTUAL, 6 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2016

			JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 104,953,817	$ 107,346,359	$ 104,419,313	$ 98,063,519	$ 83,543,398	$ 92,467,952	$ 1,131,663,607
	2	Fuel Cost of Power Sold	(2,540,491)	(2,584,887)	(2,111,545)	(1,805,691)	(1,522,351)	(1,698,236)	(25,950,865)
	3	Fuel Cost of Purchased Power	20,235,740	20,086,620	17,363,635	11,608,789	7,945,939	4,274,978	191,602,712
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	11,644,372	11,687,183	10,720,507	9,892,299	11,332,121	12,008,298	123,122,350
	4	Energy Cost of Economy Purchases	285,457	315,966	252,602	470,078	462,356	268,909	4,283,329
	5	Adjustments to Fuel Cost	(4,357,619)	(20,508)	(18,630)	(16,142)	(12,413)	2,316	(4,524,968)
	6	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Through A5)	130,221,276	136,830,734	130,625,882	118,212,851	101,749,050	107,324,217	1,420,196,164
B	1	Jurisdictional MWH Sales	3,746,390	3,802,397	3,818,043	3,520,143	2,939,053	2,841,931	38,350,239
	2	Non-Jurisdictional MWH Sales	22,211	24,219	21,223	18,003	12,892	17,383	315,264
	3	TOTAL SALES (Lines B1 + B2)	3,768,601	3,826,616	3,839,266	3,538,146	2,951,945	2,859,314	38,665,503
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.41%	99.37%	99.45%	99.49%	99.56%	99.39%	99.18%
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	111,627,849	113,309,102	113,778,746	104,836,277	87,392,895	84,477,439	1,187,368,166
	1a	RRSSA Refund - $60M	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	5,000,000	60,000,000
	1b	RRSSA Fuel Adjustment	-	-	-	-	-	-	-
	1c	RRSSA Refund - $10M	833,333	833,333	833,333	833,333	833,333	833,333	10,000,000
	2	True-Up Provision	10,764,480	10,764,480	10,764,480	10,764,480	10,764,480	10,790,295	116,588,896
	2a	Incentive Provision	717,816	717,816	717,816	717,816	717,816	717,821	8,613,797
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Through C2a)	128,943,479	130,624,732	131,094,376	122,151,906	104,708,525	101,818,889	1,382,570,859
	4	Fuel & Net Power Transactions (Line A6)	130,221,276	136,830,734	130,625,882	118,212,851	101,749,050	107,324,217	1,420,196,164
	5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line A6 * Line B4 * Line Loss Multiplier)	129,504,751	136,023,087	129,959,403	117,657,009	101,341,875	106,712,207	1,408,980,487
	6	Over/(Under) Recovery (Line C3 - Line C5)	(561,273)	(5,398,356)	1,134,973	4,494,897	3,366,650	(4,893,319)	(26,409,628)
	7	Interest Provision	10,719	6,461	2,466	2	(2,116)	(5,695)	217,781
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	(550,554)	(5,391,894)	1,137,438	4,494,899	3,364,533	(4,899,014)	(26,191,847)
	9	Plus: Prior Period Balance	116,563,080	116,563,080	116,563,080	116,563,080	116,563,080	116,563,080	116,563,080
	10	Plus: Cumulative True-Up Provision	(62,740,679)	(73,505,160)	(84,269,640)	(95,034,120)	(105,798,601)	(116,588,896)	(116,588,896)
	11	Subtotal Prior Period True-up	53,822,401	43,057,920	32,293,440	21,528,960	10,764,479	(25,816)	(25,816)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	$28,924,591	$12,768,217	$3,141,175	($3,128,407)	($10,528,354)	($26,217,663)	($26,217,663)

Duke Energy Florida
Calculation of Generating Performance Incentive
And True-Up Adjustment Factors
Estimated for the Period of : January through December 2017

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward / (Penalty)	$	2,255,421
	B. True-Up (Over) / Under Recovery	$	26,217,663
2.	JURISDICTIONAL mWh SALES	mWh	39,214,036
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor	Cents/kWh	0.006
	B. True-Up Factor	Cents/kWh	0.067

Duke Energy Florida
Calculation of Levelized Fuel Adjustment Factors
Estimated for the Period of : January through December 2017

1.	Period Jurisdictional Fuel Cost (Schedule E-1, line 22)	$	1,406,748,451	
1a.	Prior Period True-up (E1, Line 23)	$	26,217,663	
2.	Regulatory Assessment Fee (E1, Line 25)	$	1,031,736	
3.	Generating Performance Incentive Factor (GPIF) (E1, Line 27)	$	2,255,421	
4.	Total amount to be Recovered	$	1,436,253,271	
5.	Jurisdictional Sales (January - December 2017)		39,214,036	mWh
6.	Jurisdictional Cost per kWh Sold (Line 4 / Line 5 / 10)		3.663	Cents/kWh
7.	Effective Jurisdictional Sales (See Below)		39,166,332	mWh
	LEVELIZED FUEL FACTORS:			
8.	Fuel Factor at Secondary Metering (Line 4 / Line 7 / 10)		3.667	Cents/kWh
9.	Fuel Factor at Primary Metering		3.630	Cents/kWh
10.	Fuel Factor at Transmission Metering		3.594	Cents/kWh
	TIERED FUEL FACTORS:			
11	Fuel Factor - First Tier (0-1000 kWh)		3.377	Cents/kWh
12	Fuel Factor - Second Tier (Over 1000 kWh)		4.377	Cents/kWh

	JURISDICTIONAL SALES (mWh)	
METERING VOLTAGE:	METER	SECONDARY
Distribution Secondary	34,732,093	34,732,093
Distribution Primary	4,193,265	4,151,332
Transmission	288,680	282,906
Total	39,214,038	39,166,332

Duke Energy Florida
Calculation of Final Fuel Cost Factors
Estimated for the Period of : January through December 2017

Line:	Metering Voltage	First Tier Factor Cents/kWh	Second Tier Factor Cents/kWh	Levelized Factors Cents/kWh	----------Time of Use---------- On-Peak Multiplier 1.247	Off-Peak Multiplier 0.885
1.	Distribution Secondary	3.377	4.377	3.667	4.573	3.245
2.	Distribution Primary	--	--	3.630	4.527	3.213
3.	Transmission	--	--	3.594	4.482	3.181
4.	Lighting Service	--	--	3.494	--	--

Line 4 calculated at secondary rate of 3.667 * (18.7% * On-Peak Multiplier 1.247 + 81.3% * Off-Peak Multiplier 0.885).

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-17	873,422	29,224,114	3.346	2,375,283	60,017,286	2.527	3,248,705	89,241,400	2.747
Feb-17	761,550	23,811,466	3.127	2,019,184	52,602,764	2.605	2,780,734	76,414,230	2.748
Mar-17	812,816	23,513,479	2.893	2,207,717	60,434,936	2.737	3,020,533	83,948,415	2.779
Apr-17	983,250	35,599,102	3.621	2,087,454	53,609,537	2.568	3,070,705	89,208,639	2.905
May-17	1,358,300	51,187,028	3.768	2,367,439	57,886,049	2.445	3,725,740	109,073,078	2.928
Jun-17	1,436,913	56,114,917	3.905	2,596,108	67,803,584	2.612	4,033,020	123,918,501	3.073
Jul-17	1,428,381	61,069,925	4.275	2,851,812	77,588,407	2.721	4,280,194	138,658,332	3.240
Aug-17	1,566,184	66,696,607	4.259	2,779,608	76,878,153	2.766	4,345,792	143,574,760	3.304
Sep-17	1,359,081	53,078,141	3.905	2,644,013	70,596,811	2.670	4,003,094	123,674,952	3.089
Oct-17	1,201,154	49,604,752	4.130	2,296,150	62,944,463	2.741	3,497,304	112,549,216	3.218
Nov-17	771,942	20,762,043	2.690	2,154,582	57,494,720	2.668	2,926,524	78,256,763	2.674
Dec-17	827,088	25,666,990	3.103	2,365,790	59,160,124	2.501	3,192,878	84,827,113	2.657
TOTAL	13,380,080	496,328,565	3.709	28,745,142	757,016,834	2.634	42,125,222	1,253,345,400	2.975

MARGINAL FUEL COST	ON-PEAK	OFF-PEAK	AVERAGE
WEIGHTING MULTIPLIER	1.247	0.885	1.000

Duke Energy Florida
Development of Jurisdictional Delivery Loss Multipliers
Based on Actual Twelve Months Ending December 31, 2015
Estimated for the Period of : January through December 2017

		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		288,867	781	289,648		0.9862055	293,700		
Distribution Primary		4,131,208	11,174	4,142,382		0.9762055	4,243,351		
Distribution Secondary		34,133,108	92,313	34,225,421		0.9467387	36,150,863		
Total Retail		38,553,183	104,268	38,657,451	99.17%	0.9500967	40,687,914	99.21%	1.00040
						4.99%			
Wholesale									
Generation Level		304,498	(11,250)	293,249		1.0000000	293,249		
Transmission		-	-	-		0.9862055	-		
Distribution Primary		30,966	(1,387)	29,578		0.9762055	30,299		
Distribution Secondary		-	-	-			-		
Total Wholesale		335,464	(12,637)	322,827	0.83%	0.9977717	323,548	0.79%	0.95260
						0.22%			
Subtotal Class		38,888,647	91,631	38,980,278	100.00%	0.9504728	41,011,462	100.00%	1.00000
						4.95%			
Non-Class									
SEPA	Transmission	22,105	-	22,105		0.9862055	22,414		
Homestead Base & Int	Generation	135,871	(6,335)	129,536		1.0000000	129,536		
SECI - Base	Generation	341,240	(3,554)	337,686		1.0000000	337,686		
Reedy Creek Base & Int	Generation	370,647	(17,281)	353,366		1.0000000	353,366		
NSB - Peaking	Generation	2,129	-	2,129		1.0000000	2,129		
SECI - Intermediate	Generation	34,925	(364)	34,561		1.0000000	34,561		
SECI - Peaking	Generation	677	(7)	670		1.0000000	670		
Interchange	Generation	180,985	-	180,985		1.0000000	180,985		
Company Use	Secondary	175,126	-	175,126		0.9467387	184,978		
Total Non-Class		1,263,704	(27,540)	1,236,164			1,246,326		
Total System		40,152,352	64,091	40,216,443		0.951693	42,257,788		

Docket No. 160001-EI
Schedule E2
Exhibit CAM-3, Part 2

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January through December 2017

			Estimated Jan-17	Estimated Feb-17	Estimated Mar-17	Estimated Apr-17	Estimated May-17	Estimated Jun-17	Estimated Jul-17	Estimated Aug-17	Estimated Sep-17	Estimated Oct-17	Estimated Nov-17	Estimated Dec-17	TOTAL
1	Fuel Cost of System Net Generation		$96,468,913	$82,466,077	$87,872,028	$85,375,316	$107,291,793	$111,149,953	$116,140,966	$117,154,699	$110,750,652	$107,900,721	$95,704,871	$103,562,549	$1,221,838,538
1a	Nuclear Fuel Disposal Cost		0	0	0	0	0	0	0	0	0	0	0	0	0
1b	Adjustments to Fuel Cost		0	0	0	0	0	0	0	0	0	0	0	0	0
2	Fuel Cost of Power Sold		(293,948)	(193,248)	(194,137)	(325,957)	(244,693)	(209,097)	(114,697)	(190,326)	(81,602)	(81,590)	(433,168)	(153,818)	(2,516,281)
2a	Gains on Power Sales		(71,551)	(47,038)	(47,256)	(79,340)	(59,560)	(50,896)	(27,919)	(46,327)	(19,864)	(19,860)	(105,436)	(37,441)	(612,488)
2b	Fuel Cost of Stratified Sales		(1,602,253)	(1,058,435)	(1,793,288)	(2,017,970)	(2,377,019)	(2,446,981)	(2,684,330)	(2,703,432)	(2,335,392)	(1,969,320)	(1,209,264)	(1,607,290)	(23,804,974)
3	Fuel Cost of Purchased Power (Excl Economy)		1,962,180	1,072,370	3,990,930	4,898,231	5,717,238	9,019,357	11,445,908	12,556,538	9,356,711	9,989,330	2,478,737	1,323,796	73,811,326
3a	Energy Payments to Qualifying Facilities		12,177,556	11,032,109	11,823,009	11,229,874	12,066,147	11,745,616	12,199,522	12,276,250	11,889,369	10,297,653	11,450,142	12,408,768	140,596,014
4	Energy Cost of Economy Purchases		309,512	262,567	448,037	345,239	320,118	308,450	446,632	415,544	327,741	607,566	355,128	271,115	4,417,649
5	Total System Fuel & Net Power Transactions		$108,950,409	$93,534,403	$102,099,322	$99,425,393	$122,714,024	$129,516,402	$137,406,082	$139,462,946	$129,887,615	$126,724,500	$108,241,010	$115,767,679	$1,413,729,784
6	Jurisdictional mWh Sold		3,162,399	2,819,126	2,657,486	2,661,601	3,023,218	3,592,575	3,831,104	4,024,630	3,904,886	3,583,805	3,031,751	2,921,454	39,214,036
7	Jurisdictional % of Total Sales		99.42%	99.56%	99.57%	99.49%	99.42%	99.44%	99.42%	99.40%	99.46%	99.50%	99.57%	99.41%	99.47%
8	Jurisdicitonal Fuel & Net Power Transactions		108,318,497	93,122,851	101,660,295	98,918,323	122,002,282	128,791,110	136,609,127	138,626,168	129,186,222	126,090,878	107,775,573	115,084,650	1,406,185,977
9	Jurisdictional Loss Multiplier		1.00040	1.00040	1.00040	1.00040	1.00040	1.00040	1.00040	1.00040	1.00040	1.00040	1.00040	1.00040	1.00040
10	Jurisdictional Fuel & Net Power Transactions		108,361,824	93,160,100	101,700,960	98,957,891	122,051,083	128,842,627	136,663,771	138,681,618	129,237,896	126,141,314	107,818,684	115,130,684	1,406,748,451
11	Adjusted System Sales	mWh	3,181,002	2,831,659	2,669,044	2,675,245	3,040,924	3,612,781	3,853,368	4,048,886	3,926,138	3,601,835	3,044,712	2,938,890	39,424,485
12	System Cost per kWh Sold	c/kWh	3.4250	3.3031	3.8253	3.7164	4.0354	3.5849	3.5659	3.4445	3.3083	3.5183	3.5550	3.9392	3.5859
13	Jurisdictional Loss Multiplier	x	1.0004	1.0004	1.0004	1.0004	1.0004	1.0004	1.0004	1.0004	1.0004	1.0004	1.0004	1.0004	1.00040
14	Jurisdictional Cost per kWh Sold	c/kWh	3.4266	3.3046	3.8270	3.7180	4.0371	3.5864	3.5672	3.4458	3.3096	3.5198	3.5563	3.9409	3.5874
15	Prior Period True-Up	+	0.0691	0.0775	0.0822	0.0821	0.0723	0.0608	0.0570	0.0543	0.0560	0.0610	0.0721	0.0748	0.0669
16	Total Jurisdictional Fuel Expense	c/kWh	3.4957	3.3821	3.9092	3.8001	4.1094	3.6472	3.6242	3.5001	3.3656	3.5807	3.6284	4.0156	3.6542
17	Revenue Tax Multiplier	x	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
18	Recovery Factor Adjusted for Taxes	c/kWh	3.4982	3.3845	3.9120	3.8028	4.1124	3.6498	3.6269	3.5026	3.3680	3.5833	3.6310	4.0185	3.6569
19	GPIF	+	0.0059	0.0067	0.0071	0.0071	0.0062	0.0052	0.0049	0.0047	0.0048	0.0052	0.0062	0.0064	0.0058
20	Total Recovery Factor (rounded .001)	c/kWh	3.504	3.391	3.919	3.810	4.119	3.655	3.632	3.507	3.373	3.589	3.637	4.025	3.663

Duke Energy Florida

Generating System Comparative Data by Fuel Type

Estimated for the Period of : January through December 2017

			Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Subtotal
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		0	0	0	0	0	0	0
2	LIGHT OIL		336,416	331,140	282,943	354,161	364,984	325,659	1,995,303
3	COAL		28,240,918	24,446,219	26,430,916	20,346,221	28,929,952	29,375,644	157,769,870
4	GAS		67,891,579	57,688,718	61,158,169	64,674,934	77,996,857	81,448,650	410,858,907
5	NUCLEAR		0	0	0	0	0	0	0
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	96,468,913	82,466,077	87,872,028	85,375,316	107,291,793	111,149,953	570,624,080
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		0	0	0	0	0	0	0
9	LIGHT OIL		241	60	41	13	6	8	369
10	COAL		894,094	787,755	875,472	668,195	916,894	943,900	5,086,310
11	GAS		2,022,683	1,708,082	1,780,374	2,015,353	2,373,869	2,580,407	12,480,767
12	NUCLEAR		0	0	0	0	0	0	0
13	SOLAR		1,429	1,298	1,605	3,598	3,617	3,241	14,788
14	OTHER		0	0	0	0	0	0	0
15	TOTAL	MWH	2,918,447	2,497,195	2,657,492	2,687,159	3,294,386	3,527,555	17,582,234
	UNITS OF FUEL BURNED								
16	HEAVY OIL	BBL	0	0	0	0	0	0	0
17	LIGHT OIL	BBL	2,185	2,079	1,305	2,422	2,576	1,948	12,515
18	COAL	TON	400,765	353,830	395,102	308,636	426,658	437,356	2,322,347
19	GAS	MCF	15,055,796	12,672,432	13,267,285	15,402,715	18,151,858	19,691,160	94,241,246
20	NUCLEAR	MMBTU	0	0	0	0	0	0	0
21	OTHER		0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
22	HEAVY OIL		0	0	0	0	0	0	0
23	LIGHT OIL		12,740	12,114	7,598	14,101	15,003	11,342	72,898
24	COAL		9,110,066	8,035,479	8,961,300	6,994,418	9,715,706	9,950,205	52,767,174
25	GAS		15,055,796	12,672,432	13,267,285	15,402,715	18,151,858	19,691,160	94,241,246
26	NUCLEAR		0	0	0	0	0	0	0
27	OTHER		0	0	0	0	0	0	0
28	TOTAL	MMBTU	24,178,602	20,720,025	22,236,183	22,411,234	27,882,567	29,652,707	147,081,318
	GENERATION MIX (% MWH)								
29	HEAVY OIL		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
30	LIGHT OIL		0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
31	COAL		30.64%	31.55%	32.94%	24.87%	27.83%	26.76%	28.93%
32	GAS		69.31%	68.40%	67.00%	75.00%	72.06%	73.15%	70.99%
33	NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	SOLAR		0.05%	0.05%	0.06%	0.13%	0.11%	0.09%	0.08%
35	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
36	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
37	HEAVY OIL	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
38	LIGHT OIL	$/BBL	153.97	159.28	216.81	146.23	141.69	167.18	159.43
39	COAL	$/TON	70.47	69.09	66.90	65.92	67.81	67.17	67.94
40	GAS	$/MCF	4.51	4.55	4.61	4.20	4.30	4.14	4.36
41	NUCLEAR	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
43	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	LIGHT OIL		26.41	27.34	37.24	25.12	24.33	28.71	27.37
45	COAL		3.10	3.04	2.95	2.91	2.98	2.95	2.99
46	GAS		4.51	4.55	4.61	4.20	4.30	4.14	4.36
47	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
48	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
49	TOTAL	$/MMBTU	3.99	3.98	3.95	3.81	3.85	3.75	3.88
	BTU BURNED PER KWH (BTU/KWH)								
50	HEAVY OIL		0	0	0	0	0	0	0
51	LIGHT OIL		52,951	200,563	185,317	1,119,127	2,500,500	1,417,750	197,770
52	COAL		10,189	10,200	10,236	10,468	10,596	10,542	10,374
53	GAS		7,443	7,419	7,452	7,643	7,647	7,631	7,551
54	NUCLEAR		0	0	0	0	0	0	0
55	OTHER		0	0	0	0	0	0	0
56	TOTAL	BTU/KWH	8,285	8,297	8,367	8,340	8,464	8,406	8,365
	GENERATED FUEL COST PER KWH (C/KWH)								
57	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	LIGHT OIL		139.82	548.25	690.10	2810.80	6083.07	4070.74	541.32
59	COAL		3.16	3.10	3.02	3.04	3.16	3.11	3.10
60	GAS		3.36	3.38	3.44	3.21	3.29	3.16	3.29
61	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
62	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
63	TOTAL	C/KWH	3.31	3.30	3.31	3.18	3.26	3.15	3.25

Duke Energy Florida

Generating System Comparative Data by Fuel Type

Estimated for the Period of : January through December 2017

			Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		0	0	0	0	0	0	0
2	LIGHT OIL		290,364	368,505	372,783	269,987	386,250	356,069	4,039,261
3	COAL		31,955,839	31,416,565	29,149,530	18,718,186	18,119,265	23,724,082	310,853,337
4	GAS		83,894,763	85,369,629	81,228,339	88,912,548	77,199,356	79,482,398	906,945,940
5	NUCLEAR		0	0	0	0	0	0	0
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	116,140,966	117,154,699	110,750,652	107,900,721	95,704,871	103,562,549	1,221,838,538
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		0	0	0	0	0	0	0
9	LIGHT OIL		0	18	76	27	12	27	529
10	COAL		1,041,837	1,031,530	961,858	649,789	649,142	865,747	10,286,213
11	GAS		2,655,720	2,711,366	2,520,136	2,356,280	1,971,130	2,005,435	26,700,833
12	NUCLEAR		0	0	0	0	0	0	0
13	SOLAR		3,185	2,981	3,050	3,209	2,699	2,644	32,556
14	OTHER		0	0	0	0	0	0	0
15	TOTAL	MWH	3,700,743	3,745,895	3,485,119	3,009,304	2,622,983	2,873,853	37,020,131
	UNITS OF FUEL BURNED								
16	HEAVY OIL	BBL	0	0	0	0	0	0	0
17	LIGHT OIL	BBL	1,394	2,581	2,630	1,061	2,839	2,402	25,422
18	COAL	TON	480,852	475,901	444,791	299,087	294,557	390,226	4,707,761
19	GAS	MCF	20,336,850	20,743,588	19,200,406	18,089,452	14,492,163	14,779,435	201,883,140
20	NUCLEAR	MMBTU	0	0	0	0	0	0	0
21	OTHER		0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
22	HEAVY OIL		0	0	0	0	0	0	0
23	LIGHT OIL		8,125	15,038	15,317	6,180	16,529	13,991	148,078
24	COAL		10,937,231	10,819,857	10,109,282	6,773,879	6,660,354	8,822,991	106,890,768
25	GAS		20,336,850	20,743,588	19,200,406	18,089,452	14,492,163	14,779,435	201,883,140
26	NUCLEAR		0	0	0	0	0	0	0
27	OTHER		0	0	0	0	0	0	0
28	TOTAL	MMBTU	31,282,206	31,578,483	29,325,005	24,869,511	21,169,046	23,616,417	308,921,986
	GENERATION MIX (% MWH)								
29	HEAVY OIL		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
30	LIGHT OIL		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
31	COAL		28.15%	27.54%	27.60%	21.59%	24.75%	30.13%	27.79%
32	GAS		71.76%	72.38%	72.31%	78.30%	75.15%	69.78%	72.13%
33	NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	SOLAR		0.09%	0.08%	0.09%	0.11%	0.10%	0.09%	0.09%
35	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
36	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
37	HEAVY OIL	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
38	LIGHT OIL	$/BBL	208.30	142.78	141.74	254.46	136.05	148.24	158.89
39	COAL	$/TON	66.46	66.01	65.54	62.58	61.51	60.80	66.03
40	GAS	$/MCF	4.13	4.12	4.23	4.92	5.33	5.38	4.49
41	NUCLEAR	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
43	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	LIGHT OIL		35.74	24.51	24.34	43.69	23.37	25.45	27.28
45	COAL		2.92	2.90	2.88	2.76	2.72	2.69	2.91
46	GAS		4.13	4.12	4.23	4.92	5.33	5.38	4.49
47	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
48	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
49	TOTAL	$/MMBTU	3.71	3.71	3.78	4.34	4.52	4.39	3.96
	BTU BURNED PER KWH (BTU/KWH)								
50	HEAVY OIL		0	0	0	0	0	0	0
51	LIGHT OIL		0	817,283	202,874	231,461	1,343,821	514,375	280,079
52	COAL		10,498	10,489	10,510	10,425	10,260	10,191	10,392
53	GAS		7,658	7,651	7,619	7,677	7,352	7,370	7,561
54	NUCLEAR		0	0	0	0	0	0	0
55	OTHER		0	0	0	0	0	0	0
56	TOTAL	BTU/KWH	8,453	8,430	8,414	8,264	8,071	8,218	8,345
	GENERATED FUEL COST PER KWH (C/KWH)								
57	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	LIGHT OIL		0.00	2002.74	493.75	1011.19	3140.24	1309.08	764.00
59	COAL		3.07	3.05	3.03	2.88	2.79	2.74	3.02
60	GAS		3.16	3.15	3.22	3.77	3.92	3.96	3.40
61	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
62	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
63	TOTAL	C/KWH	3.14	3.13	3.18	3.59	3.65	3.60	3.30

Docket No. 160001-EI
Schedule E4
Exh bit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Jan-17

(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	1	376	691	0 2	90.65	36.8	10,910	COAL	319	TONS	23 63	7,539	32,916	4.76
2 CRYSTAL RIVER	2	500	968	0 3	97.74	38.7	10,927	COAL	448	TONS	23 61	10,577	44,519	4.60
3 CRYSTAL RIVER	4	732	416,249	76.4	89.35	85.5	10,247	COAL	187,657	TONS	22.73	4,265,445	13,220,514	3.18
4 CRYSTAL RIVER	5	712	476,186	89 9	98.06	92.0	10,136	COAL	212,341	TONS	22.73	4,826,505	14,942,969	3.14
5 ANCLOTE	1	517	36,839	9 6	88.39	44.3	11,031	GAS	406,355	MCF	1 00	406,355	2,329,658	6.32
6 ANCLOTE	2	521	117,718	30.4	97.10	31.3	10,835	GAS	1,275,450	MCF	1 00	1,275,450	5,254,163	4.46
7 AVON PARK	1-2	69	0	0 0	0.00	0.0	0	GAS	0	MCF	0 00	0	0	0.00
8 BARTOW	1-4	228	177	0.1	81.61	19.4	13,237	GAS	2,343	MCF	1 00	2,343	10,565	5.97
9 BARTOW CC	1	1279	771,030	81 0	98.06	82.6	7,109	GAS	5,481,169	MCF	1 00	5,481,169	24,716,410	3.21
10 CITRUS CC	1-2	1586	0	0 0	0.00	0.0	0	GAS	0	MCF	0 00	0	0	0.00
11 DEBARY	1-10	785	648	0.1	96.52	15.0	12,424	GAS	8,048	MCF	1 00	8,048	36,290	5.60
12 HIGGINS	1-4	129	54	0.1	92.42	20.8	15,690	GAS	841	MCF	1 00	841	3,794	7.08
13 HINES CC	1-4	2,204	1,009,996	61 6	94.84	22.6	7,060	GAS	7,130,851	MCF	1 00	7,130,851	32,155,370	3.18
14 NT CITY	1-14	1,186	3,308	0.4	95.74	8.1	12,389	GAS	40,982	MCF	1 00	40,982	184,803	5.59
15 OSPREY CC	1	505	31,908	8 5	96.13	48.2	7,814	GAS	249,337	MCF	1 00	249,337	1,124,343	3.52
16 SUWANNEE STEAM	1	67	0	0 0	0.00	0.0	0	GAS	0	MCF	0 00	0	0	0.00
17 SUWANNEE STEAM	2	66	0	0 0	0.00	0.0	0	GAS	0	MCF	0 00	0	0	0.00
18 SUWANNEE STEAM	3	67	0	0 0	0.00	0.0	0	GAS	0	MCF	0 00	0	0	0.00
19 SUWANNEE CT	1-3	200	308	0 2	99.24	41.0	12,336	GAS	3,802	MCF	1 00	3,802	17,142	5.56
20 TIGER BAY CC	1	225	15,792	9.4	92.58	97.5	8,077	GAS	127,554	MCF	1 00	127,554	575,183	3.64
21 UNIV OF FLA. CC	1	47	34,906	99 8	97.74	102.2	9,427	GAS	329,064	MCF	1 00	329,064	1,483,858	4.25
22 AVON PARK	1-2	69	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	0 00	0	0	0.00
23 BARTOW	1-4	228	0	0 0	81.61	0.0	0	LIGHT OIL	0	BBLS	0 00	0	0	0.00
24 BAYBORO	1-4	231	0	0 0	95.65	0.0	0	LIGHT OIL	0	BBLS	0 00	0	96	0.00
25 DEBARY	1-10	785	58	0.1	96.52	89.9	15,226	LIGHT OIL	150	BBLS	5 85	877	13,489	23.42
26 HIGGINS	1-4	129	0	0 0	92.42	0.0	0	LIGHT OIL	0	BBLS	0 00	0	0	0.00
27 OTHER		0	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	0 00	0	0	0.00
28 NT CITY	1-14	1,186	163	0.4	95.74	292.7	12,898	LIGHT OIL	360	BBLS	5 85	2,105	27,380	16.78
29 RIO PINAR	1	16	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	0 00	0	0	0.00
30 SUWANNEE	1-3	200	20	0 2	99.24	0.0	12,828	LIGHT OIL	44	BBLS	5.77	254	3,997	20.19
31 TURNER	1-4	199	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	0 00	0	0	0.00
32 OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,631	BBLS	5 83	9,504	291,454	0.00
33 SOLAR		19	1,429	10.1	0.00	0.0	0	SOLAR	0	N/A		0	0	0.00
34 TOTAL			2,918,447									24,178,602	96,468,913	3.31

Docket No. 160001-EI
Schedule E4
Exhibit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Feb-17

	(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	1	376	0	0 0	89.64	0.0	0	COAL	0	TONS	0.00	0	4,071	0 00
2	CRYSTAL RIVER	2	500	0	0 0	96.07	0.0	0	COAL	0	TONS	0.00	0	4,071	0 00
3	CRYSTAL RIVER	4	732	385,233	75 6	92.50	84.6	10,260	COAL	174,034	TONS	22.71	3,952,313	12,022,104	3.12
4	CRYSTAL RIVER	5	712	402,522	81 2	93.57	91.2	10,144	COAL	179,796	TONS	22.71	4,083,166	12,415,973	3 08
5	ANCLOTE	1	517	20,387	5.7	87.14	39.0	11,331	GAS	231,001	MCF	1.00	231,001	1,564,216	7 67
6	ANCLOTE	2	521	96,753	26.7	92.14	30.0	10,924	GAS	1,056,957	MCF	1.00	1,056,957	4,298,956	4.44
7	AVON PARK	1-2	69	0	0 0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
8	BARTOW	1-4	228	11	0 0	82.41	0.0	13,421	GAS	153	MCF	1.00	153	696	6.11
9	BARTOW CC	1	1279	678,780	76 3	96.43	81.9	7,119	GAS	4,832,001	MCF	1.00	4,832,001	21,996,722	3 24
10	CITRUS CC	1-2	1586	0	0 0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
11	DEBARY	1-10	785	184	0 0	96.64	13.5	12,439	GAS	2,290	MCF	1.00	2,290	10,423	5 66
12	HIGG NS	1-4	129	0	0 0	91.07	0.0	0	GAS	0	MCF	0.00	0	0	0 00
13	H NES CC	1-4	2,204	850,237	55.4	94.88	22.7	7,050	GAS	5,994,120	MCF	1.00	5,994,120	27,287,037	3 21
14	INT CITY	1-14	1,186	3,097	0.4	95.37	8.0	12,413	GAS	38,444	MCF	1.00	38,444	175,010	5 65
15	OSPREY CC	1	505	17,397	4 9	97.86	48.5	7,971	GAS	138,668	MCF	1.00	138,668	631,257	3 63
16	SUWANNEE STEAM	1	67	0	0 0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
17	SUWANNEE STEAM	2	66	0	0 0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
18	SUWANNEE STEAM	3	67	0	0 0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
19	SUWANNEE CT	1-3	200	54	0 0	99.05	0.0	12,239	GAS	656	MCF	1.00	656	2,986	5 57
20	TIGER BAY CC	1	225	9,847	6 3	91.43	95.1	8,402	GAS	82,731	MCF	1.00	82,731	376,616	3 82
21	UNIV OF FLA. CC	1	47	31,334	95 8	97.14	102.1	9,428	GAS	295,411	MCF	1.00	295,411	1,344,799	4 29
22	AVON PARK	1-2	69	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
23	BARTOW	1-4	228	0	0 0	82.41	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
24	BAYBORO	1-4	231	5	0 0	95.90	0.0	13,846	LIGHT OIL	12	BBLS	6.00	72	873	16.79
25	DEBARY	1-10	785	27	0 0	96.64	0.0	14,743	LIGHT OIL	68	BBLS	5.90	401	8,395	30 86
26	HIGG NS	1-4	129	0	0 0	91.07	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
27	OTHER		0	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
28	INT CITY	1-14	1,186	22	0.4	95.37	263.0	15,670	LIGHT OIL	60	BBLS	5.85	351	8,753	39 08
29	RIO P NAR	1	16	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
30	SUWANNEE	1-3	200	6	0 0	99.05	0.0	14,107	LIGHT OIL	14	BBLS	5.64	79	2,070	36 96
31	TURNER	1-4	199	0	0 0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
32	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,925	BBLS	5.82	11,211	311,049	0 00
33	SOLAR		19	1,298	9 8	0.00	0.0	0	SOLAR	0	N/A		0	0	0 00
34	TOTAL			2,497,195									20,720,025	82,466,077	3 30

Docket No. 160001-EI
Schedule E4
Exhibit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Mar-17

	(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 1	376	925	0.3	87.42	35.1	10,802	COAL	423 TONS	23.62	9,992	42,240	4.57
2	CRYSTAL RIVER 2	500	0	0.0	93 87	0 0	0	COAL	0 TONS	0.00	0	4,071	0.00
3	CRYSTAL RIVER 4	732	427,280	78.5	96.13	81 6	10,297	COAL	193,988 TONS	22.68	4,399,645	12,970,355	3.04
4	CRYSTAL RIVER 5	712	447,267	84.4	96.45	88.1	10,177	COAL	200,691 TONS	22.68	4,551,663	13,414,250	3.00
5	ANCLOTE 1	517	2,385	0.6	85 00	38.4	11,735	GAS	27,988 MCF	1.00	27,988	985,027	41.30
6	ANCLOTE 2	521	127,225	32.8	94 52	34.7	10,719	GAS	1,363,731 MCF	1.00	1,363,731	5,430,378	4.27
7	AVON PARK 1-2	69	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
8	BARTOW 1-4	228	44	0.0	82.42	0 0	13,555	GAS	591 MCF	1.00	591	2,728	6.26
9	BARTOW CC 1	1279	644,328	67.7	96.13	70 5	7,148	GAS	4,605,922 MCF	1.00	4,605,922	21,231,903	3.30
10	CITRUS CC 1-2	1586	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
11	DEBARY 1-10	785	305	0.1	95 93	13 3	12,417	GAS	3,792 MCF	1.00	3,792	17,486	5.73
12	HIGGINS 1-4	129	0	0.0	91 94	0 0	0	GAS	0 MCF	0.00	0	0	0.00
13	HINES CC 1-4	2,204	934,949	57.0	91 81	23.1	7,078	GAS	6,617,756 MCF	1.00	6,617,756	30,505,848	3.26
14	NT CITY 1-14	1,186	4,710	0.5	95 28	7.7	12,423	GAS	58,513 MCF	1.00	58,513	269,724	5.73
15	OSPREY CC 1	505	0	0.0	96 92	0 0	0	GAS	0 MCF	0.00	0	0	0.00
16	SUWANNEE STEAM 1	67	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
17	SUWANNEE STEAM 2	66	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
18	SUWANNEE STEAM 3	67	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
19	SUWANNEE CT 1-3	200	298	0.2	99 03	37 2	12,230	GAS	3,642 MCF	1.00	3,642	16,788	5.64
20	TIGER BAY CC 1	225	39,058	23.3	91 94	94 9	8,453	GAS	330,144 MCF	1.00	330,144	1,521,863	3.90
21	UNIV OF FLA. CC 1	47	27,072	77.4	97 92	102.1	9,427	GAS	255,206 MCF	1 00	255,206	1,176,424	4.35
22	AVON PARK 1-2	69	0	0.0	0 00	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
23	BARTOW 1-4	228	0	0.0	82.42	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
24	BAYBORO 1-4	231	0	0.0	95 65	0 0	0	LIGHT OIL	0 BBLS	0 00	0	96	0.00
25	DEBARY 1-10	785	8	0.1	95 93	0 0	19,750	LIGHT OIL	28 BBLS	5 64	158	5,752	71.90
26	HIGGINS 1-4	129	0	0.0	91 94	0 0	0	LIGHT OIL	0 BBLS	0 00	0	0	0.00
27	OTHER	0	0	0.0	0 00	0 0	0	LIGHT OIL	0 BBLS	0 00	0	0	0.00
28	INT CITY 1-14	1,186	33	0.5	95 28	399 9	14,364	LIGHT OIL	81 BBLS	5.85	474	10,111	30.64
29	RIO PINAR 1	16	0	0.0	0 00	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30	SUWANNEE 1-3	200	0	0.0	99 03	0 0	0	LIGHT OIL	0 BBLS		0	1,180	0.00
31	TURNER 1-4	199	0	0.0	0 00	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
32	OTHER & START UP	-	0	-	0 00	0 0	0	LIGHT OIL	1,196 BBLS	5.82	6,966	265,804	0.00
33	SOLAR	19	1,605	11.4	0 00	0 0	0	SOLAR	0 N/A		0	0	0.00
34	TOTAL		2,657,492								22,236,183	87,872,028	3.31

Docket No. 160001-EI
Schedule E4
Exhibit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Apr-17

	(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 1	376	0	0.0	84.76	0 0	0	COAL	0 TONS	0.00	0	4,121	0.00
2	CRYSTAL RIVER 2	500	1,659	0.5	96 67	41 5	10,986	COAL	772 TONS	23.61	18,226	73,743	4.45
3	CRYSTAL RIVER 4	732	258,915	49.1	87 50	84 2	10,427	COAL	119,145 TONS	22.66	2,699,829	7,871,853	3.04
4	CRYSTAL RIVER 5	712	407,621	79.5	92 64	84 3	10,491	COAL	188,719 TONS	22.66	4,276,363	12,396,504	3.04
5	ANCLOTE 1	517	73,839	19.8	89.13	56 9	10,824	GAS	799,257 MCF	1.00	799,257	3,705,126	5.02
6	ANCLOTE 2	521	133,465	35.6	93 67	38 0	10,842	GAS	1,446,983 MCF	1.00	1,446,983	5,726,678	4.29
7	AVON PARK 1-2	69	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
8	BARTOW 1-4	228	99	0.1	80 33	8.7	20,525	GAS	2,032 MCF	1.00	2,032	8,531	8.62
9	BARTOW CC 1	1279	754,545	81.9	98 67	83.1	7,274	GAS	5,488,542 MCF	1.00	5,488,542	23,046,007	3.05
10	CITRUS CC 1-2	1586	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
11	DEBARY 1-10	785	212	0.0	95.43	14 3	12,922	GAS	2,742 MCF	1.00	2,742	11,513	5.43
12	HIGGINS 1-4	129	0	0.0	92 39	0 0	0	GAS	0 MCF	0.00	0	0	0.00
13	HINES CC 1-4	2,204	935,537	59.0	94 61	22 2	7,118	GAS	6,659,407 MCF	1.00	6,659,407	27,962,389	2.99
14	NT CITY 1-14	1,186	8,621	1.0	94 81	7 8	12,806	GAS	110,400 MCF	1.00	110,400	463,566	5.38
15	OSPREY CC 1	505	31,448	8.6	97 67	72.4	7,627	GAS	239,859 MCF	1.00	239,859	1,007,151	3.20
16	SUWANNEE STEAM 1	67	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
17	SUWANNEE STEAM 2	66	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
18	SUWANNEE STEAM 3	67	0	0.0	0 00	0 0	0	GAS	0 MCF	0.00	0	0	0.00
19	SUWANNEE CT 1-3	200	315	0.2	99 33	31 5	12,229	GAS	3,851 MCF	1.00	3,851	16,170	5.13
20	TIGER BAY CC 1	225	50,546	31.2	92 00	96 8	7,863	GAS	397,443 MCF	1.00	397,443	1,668,837	3.30
21	UNIV OF FLA. CC 1	47	26,726	79.0	96 67	102.1	9,436	GAS	252,199 MCF	1.00	252,199	1,058,966	3.96
22	AVON PARK 1-2	69	0	0.0	0 00	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
23	BARTOW 1-4	228	0	0.0	80 33	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
24	BAYBORO 1-4	231	0	0.0	94 98	0 0	0	LIGHT OIL	0 BBLS	0.00	0	96	0.00
25	DEBARY 1-10	785	13	0.0	95.43	0 0	17,222	LIGHT OIL	38 BBLS	5.71	217	6,406	50.84
26	HIGGINS 1-4	129	0	0.0	92 39	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
27	OTHER	0	0	0.0	0 00	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
28	INT CITY 1-14	1,186	0	0.0	94 81	0 0	0	LIGHT OIL	0 BBLS	0.00	0	4,970	0.00
29	RIO PINAR 1	16	0	0.0	0 00	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
30	SUWANNEE 1-3	200	0	0.0	99 33	0 0	0	LIGHT OIL	0 BBLS		0	1,180	0.00
31	TURNER 1-4	199	0	0.0	0 00	0 0	0	LIGHT OIL	0 BBLS	0.00	0	0	0.00
32	OTHER & START UP	-	0	-	0 00	0 0	0	LIGHT OIL	2,384 BBLS	5.82	13,884	341,509	0.00
33	SOLAR	19	3,598	26.3	0 00	0 0	0	SOLAR	0 N/A		0	0	0.00
34	TOTAL		2,687,159								22,411,234	85,375,316	3.18

Docket No. 160001-EI
Schedule E4
Exh bit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: May-17

	(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	1	376	0	0.0	90 65	0 0	0	COAL	0	TONS	0.00	0	6,009	0.00
2	CRYSTAL RIVER	2	500	113,228	30.4	95.48	31 9	11,276	COAL	54,076	TONS	23.61	1,276,732	4,883,126	4.31
3	CRYSTAL RIVER	4	732	405,188	74.4	92 58	80 3	10,469	COAL	187,282	TONS	22.65	4,241,931	12,083,701	2.98
4	CRYSTAL RIVER	5	712	398,478	75.2	95.16	79.7	10,533	COAL	185,300	TONS	22.65	4,197,043	11,957,116	3.00
5	ANCLOTE	1	517	94,910	24.7	88.71	62 2	10,988	GAS	1,042,838	MCF	1.00	1,042,838	4,794,561	5.05
6	ANCLOTE	2	521	148,300	38.3	95.16	40 2	10,778	GAS	1,598,386	MCF	1.00	1,598,386	6,554,536	4.42
7	AVON PARK	1-2	69	0	0.0	0 00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
8	BARTOW	1-4	228	31	0.0	81 53	0 0	13,981	GAS	439	MCF	1.00	439	1,884	6.00
9	BARTOW CC	1	1279	714,930	75.1	97.42	77.1	7,260	GAS	5,190,608	MCF	1.00	5,190,608	22,303,561	3.12
10	CITRUS CC	1-2	1586	0	0.0	0 00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
11	DEBARY	1-10	785	190	0.0	96.72	12.1	12,825	GAS	2,438	MCF	1.00	2,438	10,478	5.51
12	HIGGINS	1-4	129	14	0.0	92 26	0 0	16,985	GAS	231	MCF	1.00	231	993	7.30
13	HINES CC	1-4	2,204	1,128,646	68.8	93.46	21.7	7,110	GAS	8,024,244	MCF	1.00	8,024,244	34,479,433	3.05
14	NT CITY	1-14	1,186	5,229	0.6	95.41	6 8	12,833	GAS	67,103	MCF	1.00	67,103	288,338	5.51
15	OSPREY CC	1	505	215,093	57.2	98 06	64 5	7,575	GAS	1,629,366	MCF	1.00	1,629,366	7,001,234	3.25
16	SUWANNEE STEAM	1	67	0	0.0	0 00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
17	SUWANNEE STEAM	2	66	0	0.0	0 00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
18	SUWANNEE STEAM	3	67	0	0.0	0 00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
19	SUWANNEE CT	1-3	200	83	0.1	99 07	21 6	13,101	GAS	1,090	MCF	1.00	1,090	4,684	5.63
20	TIGER BAY CC	1	225	33,213	19.8	90 65	84.4	8,488	GAS	281,907	MCF	1.00	281,907	1,211,328	3.65
21	UNIV OF FLA. CC	1	47	33,230	95.0	97.10	97 9	9,425	GAS	313,208	MCF	1.00	313,208	1,345,827	4.05
22	AVON PARK	1-2	69	0	0.0	0 00	0 0	0	LIGHT O L	0	BBLS	0.00	0	0	0.00
23	BARTOW	1-4	228	0	0.0	81 53	0 0	0	LIGHT O L	0	BBLS	0.00	0	0	0.00
24	BAYBORO	1-4	231	0	0.0	95 57	0 0	0	LIGHT O L	0	BBLS	0.00	0	96	0.00
25	DEBARY	1-10	785	0	0.0	96.72	0 0	0	LIGHT O L	0	BBLS	0.00	0	4,011	0.00
26	HIGGINS	1-4	129	0	0.0	92 26	0 0	0	LIGHT O L	0	BBLS	0.00	0	0	0.00
27	OTHER		0	0	0.0	0 00	0 0	0	LIGHT O L	0	BBLS	0.00	0	0	0.00
28	NT CITY	1-14	1,186	3	0.6	95.41	0 0	16,000	LIGHT O L	8	BBLS	6.00	48	5,490	183.00
29	RIO PINAR	1	16	0	0.0	0 00	0 0	0	LIGHT O L	0	BBLS	0.00	0	0	0.00
30	SUWANNEE	1-3	200	3	0.1	99 07	0 0	17,000	LIGHT O L	9	BBLS	5.67	51	1,757	58.57
31	TURNER	1-4	199	0	0.0	0 00	0 0	0	LIGHT O L	0	BBLS	0.00	0	0	0.00
32	OTHER & START UP		-	0	-	0 00	0 0	0	LIGHT O L	2,559	BBLS	5.82	14,904	353,630	0.00
33	SOLAR		19	3,617	25.6	0 00	0 0	0	SOLAR	0	N/A		0	0	0.00
34	TOTAL			3,294,386									27,882,567	107,291,793	3.26

Docket No. 160001-EI
Schedule E4
Exhibit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Jun-17

	(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	1	376	0	0.0	93.67	0.0	0	COAL	0	TONS	0.00	0	6,039	0 00
2	CRYSTAL RIVER	2	500	119,716	33.3	97.33	34.2	11,182	COAL	56,819	TONS	23.56	1,338,667	5,186,679	4 33
3	CRYSTAL RIVER	4	732	429,130	81.4	96.00	84.8	10,416	COAL	197,510	TONS	22.63	4,469,646	12,547,041	2 92
4	CRYSTAL RIVER	5	712	395,054	77.1	92.67	83.9	10,484	COAL	183,027	TONS	22.63	4,141,892	11,635,885	2 95
5	ANCLOTE	1	517	106,349	28.6	90.00	69.5	10,814	GAS	1,150,048	MCF	1.00	1,150,048	4,970,256	4 67
6	ANCLOTE	2	521	147,644	39.4	92.00	42.8	10,704	GAS	1,580,403	MCF	1.00	1,580,403	6,323,723	4.28
7	AVON PARK	1-2	69	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
8	BARTOW	1-4	228	71	0.0	82.25	15.6	13,933	GAS	992	MCF	1.00	992	4,103	5.76
9	BARTOW CC	1	1279	735,965	79.9	98.67	80.9	7,227	GAS	5,319,132	MCF	1.00	5,319,132	22,001,556	2 99
10	CITRUS CC	1-2	1586	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
11	DEBARY	1-10	785	594	0.1	96.77	9.6	12,812	GAS	7,605	MCF	1.00	7,605	31,457	5 30
12	HIGG NS	1-4	129	13	0.0	92.17	0.0	15,313	GAS	196	MCF	1.00	196	812	6 34
13	H NES CC	1-4	2,204	1,268,522	79.9	93.42	21.7	7,132	GAS	9,046,571	MCF	1.00	9,046,571	37,419,383	2 95
14	INT CITY	1-14	1,186	10,734	1.3	96.19	6.7	12,857	GAS	138,007	MCF	1.00	138,007	570,835	5 32
15	OSPREY CC	1	505	228,976	63.0	96.67	66.7	7,535	GAS	1,725,318	MCF	1.00	1,725,318	7,136,441	3.12
16	SUWANNEE STEAM	1	67	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
17	SUWANNEE STEAM	2	66	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
18	SUWANNEE STEAM	3	67	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
19	SUWANNEE CT	1-3	200	322	0.2	99.11	26.9	13,096	GAS	4,222	MCF	1.00	4,222	17,463	5.42
20	TIGER BAY CC	1	225	48,870	30.2	91.67	84.2	8,468	GAS	413,835	MCF	1.00	413,835	1,711,747	3 50
21	UNIV OF FLA. CC	1	47	32,347	95.6	97.67	97.9	9,424	GAS	304,831	MCF	1.00	304,831	1,260,874	3 90
22	AVON PARK	1-2	69	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
23	BARTOW	1-4	228	0	0.0	82.25	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
24	BAYBORO	1-4	231	0	0.0	95.42	0.0	0	LIGHT OIL	0	BBLS	0.00	0	96	0 00
25	DEBARY	1-10	785	8	0.1	96.77	0.0	16,750	LIGHT OIL	23	BBLS	5.83	134	5,508	68 85
26	HIGG NS	1-4	129	0	0.0	92.17	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
27	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
28	INT CITY	1-14	1,186	0	0.0	96.19	0.0	0	LIGHT OIL	0	BBLS	0.00	0	4,970	0 00
29	RIO P NAR	1	16	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
30	SUWANNEE	1-3	200	0	0.0	99.11	0.0	0	LIGHT OIL	0	BBLS		0	1,180	0 00
31	TURNER	1-4	199	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
32	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,925	BBLS	5.82	11,208	313,905	0 00
33	SOLAR		19	3,241	23.7	0.00	0.0	0	SOLAR	0	N/A		0	0	0 00
34	TOTAL			3,527,555									29,652,707	111,149,953	3.15

Docket No. 160001-EI
Schedule E4
Exh bit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Jul-17

	(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	1	376	2,313	0.8	92 26	47.3	10,723	COAL	1,055	TONS	23.51	24,802	103,279	4.47
2	CRYSTAL RIVER	2	500	130,080	35.0	95 81	36.5	11,099	COAL	61,384	TONS	23.52	1,443,757	5,665,580	4.36
3	CRYSTAL RIVER	4	732	456,012	83.7	95.16	88.0	10,380	COAL	209,174	TONS	22.63	4,733,597	13,091,465	2.87
4	CRYSTAL RIVER	5	712	453,432	85.6	98 06	87.5	10,443	COAL	209,239	TONS	22.63	4,735,075	13,095,515	2.89
5	ANCLOTE	1	517	112,214	29.2	87.42	69.6	10,793	GAS	1,211,078	MCF	1.00	1,211,078	5,221,058	4.65
6	ANCLOTE	2	521	156,587	40.4	92 26	43.8	10,676	GAS	1,671,647	MCF	1.00	1,671,647	6,670,928	4.26
7	AVON PARK	1-2	69	0	0.0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
8	BARTOW	1-4	228	27	0.0	82 82	0.0	14,191	GAS	386	MCF	1.00	386	1,590	5.85
9	BARTOW CC	1	1279	741,632	77.9	98.71	79.0	7,245	GAS	5,373,386	MCF	1.00	5,373,386	22,166,604	2.99
10	CITRUS CC	1-2	1586	0	0.0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
11	DEBARY	1-10	785	1,073	0.2	96.16	11.4	12,848	GAS	13,781	MCF	1.00	13,781	56,849	5.30
12	HIGGINS	1-4	129	0	0.0	92 26	0.0	0	GAS	0	MCF	0.00	0	0	0.00
13	HINES CC	1-4	2,204	1,295,858	79.0	92 66	21.6	7,141	GAS	9,254,228	MCF	1.00	9,254,228	38,176,083	2.95
14	INT CITY	1-14	1,186	14,653	1.7	95 58	6.7	12,842	GAS	188,174	MCF	1.00	188,174	776,269	5.30
15	OSPREY CC	1	505	248,679	66.2	95.48	69.2	7,519	GAS	1,869,831	MCF	1.00	1,869,831	7,713,536	3.10
16	SUWANNEE STEAM	1	67	0	0.0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
17	SUWANNEE STEAM	2	66	0	0.0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
18	SUWANNEE STEAM	3	67	0	0.0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
19	SUWANNEE CT	1-3	200	198	0.1	99.14	24.7	13,097	GAS	2,588	MCF	1.00	2,588	10,679	5.40
20	TIGER BAY CC	1	225	51,901	31.0	91 29	84.2	8,508	GAS	441,568	MCF	1.00	441,568	1,821,582	3.51
21	UNIV OF FLA. CC	1	47	32,899	94.1	96.13	97.9	9,428	GAS	310,183	MCF	1.00	310,183	1,279,585	3.89
22	AVON PARK	1-2	69	0	0.0	0 00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
23	BARTOW	1-4	228	0	0.0	82 82	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
24	BAYBORO	1-4	231	0	0.0	96.45	0.0	0	LIGHT OIL	0	BBLS	0.00	0	96	0.00
25	DEBARY	1-10	785	0	0.0	96.16	0.0	0	LIGHT OIL	0	BBLS	0.00	0	4,011	0.00
26	HIGGINS	1-4	129	0	0.0	92 26	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
27	OTHER		0	0	0.0	0 00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
28	INT CITY	1-14	1,186	0	0.0	95 58	0.0	0	LIGHT OIL	0	BBLS	0.00	0	4,970	0.00
29	RIO PINAR	1	16	0	0.0	0 00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
30	SUWANNEE	1-3	200	0	0.0	99.14	0.0	0	LIGHT OIL	0	BBLS		0	1,180	0.00
31	TURNER	1-4	199	0	0.0	0 00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
32	OTHER & START UP		-	0	-	0 00	0.0	0	LIGHT OIL	1,394	BBLS	5.83	8,125	280,107	0.00
33	SOLAR		19	3,185	22.5	0 00	0.0	0	SOLAR	0	N/A		0	0	0.00
34	TOTAL			3,700,743									31,282,206	116,140,966	3.14

Docket No. 160001-EI
Schedule E4
Exhibit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Aug-17

	(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	1	376	2,893	1 0	92.26	48.1	10,698	COAL	1,317	TONS	23.50	30,948	128,355	4.44
2	CRYSTAL RIVER	2	500	131,111	35 2	95.16	37 0	11,081	COAL	61,847	TONS	23.49	1,452,783	5,744,603	4.38
3	CRYSTAL RIVER	4	732	449,124	82 5	92.26	89.4	10,367	COAL	205,847	TONS	22.62	4,656,270	12,739,845	2.84
4	CRYSTAL RIVER	5	712	448,402	84 6	96.13	88 3	10,437	COAL	206,890	TONS	22.62	4,679,856	12,803,762	2.86
5	ANCLOTE	1	517	166,120	43 2	92.26	46 8	10,286	GAS	1,708,749	MCF	1.00	1,708,749	6,804,340	4.10
6	ANCLOTE	2	521	111,835	28 9	89.03	72 0	10,990	GAS	1,229,058	MCF	1.00	1,229,058	5,286,120	4.73
7	AVON PARK	1-2	69	0	0 0	0.00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
8	BARTOW	1-4	228	107	0.1	81.69	23.4	13,923	GAS	1,487	MCF	1.00	1,487	6,124	5.73
9	BARTOW CC	1	1279	723,448	76 0	95.81	79 3	7,245	GAS	5,241,402	MCF	1.00	5,241,402	21,570,837	2.98
10	CITRUS CC	1-2	1586	0	0 0	0.00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
11	DEBARY	1-10	785	883	0 2	96.36	10 3	12,816	GAS	11,313	MCF	1.00	11,313	46,557	5.27
12	HIGGINS	1-4	129	38	0 0	92.82	14.7	17,407	GAS	658	MCF	1.00	658	2,708	7.16
13	HINES CC	1-4	2,204	1,339,116	81.7	94.84	21 8	7,137	GAS	9,556,917	MCF	1.00	9,556,917	39,331,216	2.94
14	NT CITY	1-14	1,186	18,653	2.1	95.58	6.7	12,834	GAS	239,392	MCF	1.00	239,392	985,206	5.28
15	OSPREY CC	1	505	257,207	68 5	97.10	71 3	7,502	GAS	1,929,572	MCF	1.00	1,929,572	7,941,096	3.09
16	SUWANNEE STEAM	1	67	0	0 0	0.00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
17	SUWANNEE STEAM	2	66	0	0 0	0.00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
18	SUWANNEE STEAM	3	67	0	0 0	0.00	0 0	0	GAS	0	MCF	0.00	0	0	0.00
19	SUWANNEE CT	1-3	200	317	0 2	98.92	27.1	13,086	GAS	4,151	MCF	1.00	4,151	17,083	5.39
20	TIGER BAY CC	1	225	59,970	35 8	91.94	84 6	8,397	GAS	503,596	MCF	1.00	503,596	2,072,533	3.46
21	UNIV OF FLA. CC	1	47	33,672	96 3	98.39	97 9	9,423	GAS	317,293	MCF	1.00	317,293	1,305,809	3.88
22	AVON PARK	1-2	69	0	0 0	0.00	0 0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
23	BARTOW	1-4	228	0	0 0	81.69	0 0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
24	BAYBORO	1-4	231	0	0 0	95.49	0 0	0	LIGHT OIL	0	BBLS	0.00	0	96	0.00
25	DEBARY	1-10	785	4	0 2	96.36	0 0	18,372	LIGHT OIL	14	BBLS	5.64	79	4,903	114.02
26	HIGGINS	1-4	129	0	0 0	92.82	0 0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
27	OTHER		0	0	0 0	0.00	0 0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
28	NT CITY	1-14	1,186	6	2.1	95.58	0 0	15,833	LIGHT OIL	16	BBLS	5.94	95	6,030	100.50
29	RIO PINAR	1	16	0	0 0	0.00	0 0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
30	SUWANNEE	1-3	200	8	0 2	98.92	0 0	14,568	LIGHT OIL	20	BBLS	5.90	118	2,546	31.43
31	TURNER	1-4	199	0	0 0	0.00	0 0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
32	OTHER & START UP		-	0	-	0.00	0 0	0	LIGHT OIL	2,531	BBLS	5.83	14,746	354,930	0.00
33	SOLAR		19	2,981	21.1	0.00	0 0	0	SOLAR	0	N/A		0	0	0.00
34	TOTAL			3,745,895									31,578,483	117,154,699	3.13

Docket No. 160001-EI
Schedule E4
Exhibit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Sep-17

(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	1	376	5,238	1.9	92 00	38.7	10,949	COAL	2,444 TONS	23.47	57,352	233,698	4.46
2 CRYSTAL RIVER	2	500	113,994	31.7	93.79	34.9	11,152	COAL	54,166 TONS	23.47	1,271,268	5,052,947	4.43
3 CRYSTAL RIVER	4	732	427,958	81.2	93 33	87.0	10,391	COAL	196,595 TONS	22.62	4,446,982	12,083,833	2 82
4 CRYSTAL RIVER	5	712	414,668	80.9	95 00	86.7	10,451	COAL	191,586 TONS	22.62	4,333,680	11,779,052	2 84
5 ANCLOTE	1	517	143,317	38.5	89 00	43.2	10,362	GAS	1,485,029 MCF	1.00	1,485,029	6,110,142	4 26
6 ANCLOTE	2	521	103,145	27.5	97 00	66.7	11,107	GAS	1,145,599 MCF	1.00	1,145,599	5,018,872	4 87
7 AVON PARK	1-2	69	0	0.0	0 00	0.0	0	GAS	0 MCF	0.00	0	0	0 00
8 BARTOW	1-4	228	103	0.1	80 00	22.5	13,850	GAS	1,421 MCF	1.00	1,421	6,011	5 86
9 BARTOW CC	1	1279	709,320	77.0	97 00	79.3	7,247	GAS	5,140,297 MCF	1.00	5,140,297	21,746,304	3 07
10 CITRUS CC	1-2	1586	0	0.0	0 00	0.0	0	GAS	0 MCF	0.00	0	0	0 00
11 DEBARY	1-10	785	686	0.1	96 60	10.1	12,815	GAS	8,787 MCF	1.00	8,787	37,174	5.42
12 HIGG NS	1-4	129	82	0.1	92 83	15.8	16,123	GAS	1,314 MCF	1.00	1,314	5,555	6 82
13 H NES CC	1-4	2,204	1,250,560	78.8	92 97	21.7	7,144	GAS	8,934,451 MCF	1.00	8,934,451	37,797,669	3 02
14 INT CITY	1-14	1,186	8,861	1.0	95.71	6.9	12,790	GAS	113,339 MCF	1.00	113,339	479,487	5.41
15 OSPREY CC	1	505	235,084	64.7	97 33	68.0	7,527	GAS	1,769,566 MCF	1.00	1,769,566	7,486,242	3.18
16 SUWANNEE STEAM	1	67	0	0.0	0 00	0.0	0	GAS	0 MCF	0.00	0	0	0 00
17 SUWANNEE STEAM	2	66	0	0.0	0 00	0.0	0	GAS	0 MCF	0.00	0	0	0 00
18 SUWANNEE STEAM	3	67	0	0.0	0 00	0.0	0	GAS	0 MCF	0.00	0	0	0 00
19 SUWANNEE CT	1-3	200	140	0.1	99 22	39.8	13,077	GAS	1,836 MCF	1.00	1,836	7,767	5 53
20 TIGER BAY CC	1	225	50,511	31.2	91 67	84.4	8,431	GAS	425,852 MCF	1.00	425,852	1,801,590	3 57
21 UNIV OF FLA. CC	1	47	18,326	54.2	97 65	98.0	9,435	GAS	172,915 MCF	1.00	172,915	731,526	3 99
22 AVON PARK	1-2	69	0	0.0	0 00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0 00
23 BARTOW	1-4	228	0	0.0	80 00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0 00
24 BAYBORO	1-4	231	0	0.0	96 08	0.0	0	LIGHT OIL	0 BBLS	0.00	0	96	0 00
25 DEBARY	1-10	785	31	0.1	96 60	0.0	14,423	LIGHT OIL	77 BBLS	5.84	450	9,131	29 27
26 HIGG NS	1-4	129	0	0.0	92 83	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0 00
27 OTHER		0	0	0.0	0 00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0 00
28 INT CITY	1-14	1,186	26	1.0	95.71	0.0	14,078	LIGHT OIL	62 BBLS	5.79	359	9,005	35 31
29 RIO P NAR	1	16	0	0.0	0 00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0 00
30 SUWANNEE	1-3	200	19	0.1	99 22	0.0	12,979	LIGHT OIL	42 BBLS	5.81	244	4,031	21.44
31 TURNER	1-4	199	0	0.0	0 00	0.0	0	LIGHT OIL	0 BBLS	0.00	0	0	0 00
32 OTHER & START UP		-	0	-	0 00	0.0	0	LIGHT OIL	2,449 BBLS	5.82	14,264	350,520	0 00
33 SOLAR		19	3,050	22.3	0 00	0.0	0	SOLAR	0 N/A		0	0	0 00
34 TOTAL			3,485,119								29,325,005	110,750,652	3.18

Docket No. 160001-EI
Schedule E4
Exhibit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Oct-17

(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	1	376	21,712	7 8	91.29	39 0	10,957	COAL	10,140	TONS	23.46	237,893	951,402	4.38
2 CRYSTAL RIVER	2	500	0	0 0	96.25	0 0	0	COAL	0	TONS	0 00	0	4,588	0.00
3 CRYSTAL RIVER	4	732	456,649	83 8	96.45	86 9	10,395	COAL	209,845	TONS	22 62	4,746,702	12,844,038	2.81
4 CRYSTAL RIVER	5	712	171,428	32.4	95.00	87 9	10,438	COAL	79,102	TONS	22 62	1,789,284	4,918,158	2.87
5 ANCLOTE	1	517	152,971	39 8	90.32	44 0	10,340	GAS	1,581,721	MCF	1 00	1,581,721	7,325,991	4.79
6 ANCLOTE	2	521	94,319	24 3	95.00	69.1	11,022	GAS	1,039,545	MCF	1 00	1,039,545	5,557,955	5.89
7 AVON PARK	1-2	69	0	0 0	0.00	0 0	0	GAS	0	MCF	0 00	0	0	0.00
8 BARTOW	1-4	228	96	0.1	80.40	21.1	13,932	GAS	1,343	MCF	1 00	1,343	6,597	6.84
9 BARTOW CC	1	1279	687,564	72 3	93.73	75 6	7,223	GAS	4,966,053	MCF	1 00	4,966,053	24,408,943	3.55
10 CITRUS CC	1-2	1586	0	0 0	0.00	0 0	0	GAS	0	MCF	0 00	0	0	0.00
11 DEBARY	1-10	785	676	0.1	96.42	9 8	12,800	GAS	8,648	MCF	1 00	8,648	42,507	6.29
12 HIGGINS	1-4	129	29	0 0	91.29	11.4	18,571	GAS	546	MCF	1 00	546	2,686	9.14
13 HINES CC	1-4	2,204	1,099,973	67.1	94.14	21 8	7,210	GAS	7,930,804	MCF	1 00	7,930,804	38,981,167	3.54
14 NT CITY	1-14	1,186	10,630	1 2	95.16	6 8	12,827	GAS	136,341	MCF	1 00	136,341	670,138	6.30
15 OSPREY CC	1	505	229,408	61.1	98.06	68 6	7,517	GAS	1,724,544	MCF	1 00	1,724,544	8,476,409	3.69
16 SUWANNEE STEAM	1	67	0	0 0	0.00	0 0	0	GAS	0	MCF	0 00	0	0	0.00
17 SUWANNEE STEAM	2	66	0	0 0	0.00	0 0	0	GAS	0	MCF	0 00	0	0	0.00
18 SUWANNEE STEAM	3	67	0	0 0	0.00	0 0	0	GAS	0	MCF	0 00	0	0	0.00
19 SUWANNEE CT	1-3	200	99	0.1	99.34	25 5	13,087	GAS	1,293	MCF	1 00	1,293	6,353	6.43
20 TIGER BAY CC	1	225	47,285	28 2	92.00	85 8	8,151	GAS	385,425	MCF	1 00	385,425	1,894,427	4.01
21 UNIV OF FLA. CC	1	47	33,230	95 0	97.10	97 9	9,425	GAS	313,189	MCF	1 00	313,189	1,539,375	4.63
22 AVON PARK	1-2	69	0	0 0	0.00	0 0	0	LIGHT O L	0	BBLS	0 00	0	0	0.00
23 BARTOW	1-4	228	0	0 0	80.40	0 0	0	LIGHT O L	0	BBLS	0 00	0	0	0.00
24 BAYBORO	1-4	231	0	0 0	95.49	0 0	0	LIGHT O L	0	BBLS	0 00	0	96	0.00
25 DEBARY	1-10	785	18	0.1	96.42	0 0	14,746	LIGHT O L	45	BBLS	5 80	261	6,988	39.48
26 HIGGINS	1-4	129	0	0 0	91.29	0 0	0	LIGHT O L	0	BBLS	0 00	0	0	0.00
27 OTHER		0	0	0 0	0.00	0 0	0	LIGHT O L	0	BBLS	0 00	0	0	0.00
28 NT CITY	1-14	1,186	6	1 2	95.16	0 0	15,833	LIGHT O L	16	BBLS	5 94	95	6,041	100.68
29 RIO PINAR	1	16	0	0 0	0.00	0 0	0	LIGHT O L	0	BBLS	0 00	0	0	0.00
30 SUWANNEE	1-3	200	3	0.1	99.34	0 0	17,000	LIGHT O L	9	BBLS	5 67	51	1,773	59.10
31 TURNER	1-4	199	0	0 0	0.00	0 0	0	LIGHT O L	0	BBLS	0 00	0	0	0.00
32 OTHER & START UP		-	0	-	0.00	0 0	0	LIGHT O L	991	BBLS	5 83	5,773	255,089	0.00
33 SOLAR		19	3,209	22.7	0.00	0 0	0	SOLAR	0	N/A		0	0	0.00
34 TOTAL			3,009,304									24,869,511	107,900,721	3.59

Docket No. 160001-EI
Schedule E4
Exhibit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Nov-17

(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	1	376	0	0.0	88 00	0.0	0	COAL	0	TONS	0.00	0	4,071	0 00
2 CRYSTAL RIVER	2	500	1,010	0.3	96 00	28.9	11,109	COAL	478	TONS	23.47	11,220	48,729	4 82
3 CRYSTAL RIVER	4	732	395,849	75.1	94 33	79.6	10,311	COAL	180,514	TONS	22.61	4,081,419	11,061,596	2.79
4 CRYSTAL RIVER	5	712	252,283	49.2	95 50	86.8	10,178	COAL	113,565	TONS	22.61	2,567,715	7,004,869	2.78
5 ANCLOTE	1	517	102,329	27.5	86 33	31.8	10,374	GAS	1,061,578	MCF	1.00	1,061,578	4,648,424	4 54
6 ANCLOTE	2	521	5,000	1.3	96 92	35.5	12,496	GAS	62,482	MCF	1.00	62,482	1,339,417	26.79
7 AVON PARK	1-2	69	0	0.0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
8 BARTOW	1-4	228	60	0.0	81 92	11.9	13,356	GAS	800	MCF	1.00	800	4,262	7.12
9 BARTOW CC	1	1279	706,954	76.8	95 33	80.5	7,135	GAS	5,044,234	MCF	1.00	5,044,234	26,870,496	3 80
10 CITRUS CC	1-2	1586	0	0.0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
11 DEBARY	1-10	785	329	0.1	96 07	45.5	12,290	GAS	4,041	MCF	1.00	4,041	21,527	6 55
12 HIGGINS	1-4	129	30	0.0	91 92	0.0	15,814	GAS	476	MCF	1.00	476	2,539	8.44
13 HINES CC	1-4	2,204	1,022,881	64.5	95 00	27.9	7,056	GAS	7,217,591	MCF	1.00	7,217,591	38,447,903	3.76
14 NT CITY	1-14	1,186	6,795	0.8	95 36	15.6	12,513	GAS	85,031	MCF	1.00	85,031	452,957	6 67
15 OSPREY CC	1	505	90,913	25.0	96 00	63.6	7,497	GAS	681,536	MCF	1.00	681,536	3,630,524	3 99
16 SUWANNEE STEAM	1	67	0	0.0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
17 SUWANNEE STEAM	2	66	0	0.0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
18 SUWANNEE STEAM	3	67	0	0.0	0 00	0.0	0	GAS	0	MCF	0.00	0	0	0 00
19 SUWANNEE CT	1-3	200	0	0.0	99 33	0.0	0	GAS	0	MCF		0	0	0 00
20 TIGER BAY CC	1	225	2,315	1.4	98.46	93.5	7,913	GAS	18,319	MCF	1.00	18,319	97,584	4 22
21 UNIV OF FLA. CC	1	47	33,523	99.1	97 00	100.0	9,429	GAS	316,075	MCF	1.00	316,075	1,683,723	5 02
22 AVON PARK	1-2	69	0	0.0	0 00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
23 BARTOW	1-4	228	0	0.0	81 92	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
24 BAYBORO	1-4	231	0	0.0	95 33	0.0	0	LIGHT OIL	0	BBLS	0.00	0	96	0 00
25 DEBARY	1-10	785	9	0.1	96 07	0.0	18,172	LIGHT OIL	29	BBLS	5.83	169	5,935	63 82
26 HIGGINS	1-4	129	0	0.0	91 92	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
27 OTHER		0	0	0.0	0 00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
28 NT CITY	1-14	1,186	3	0.8	95 36	0.0	17,000	LIGHT OIL	9	BBLS	5.67	51	5,542	184.73
29 RIO PINAR	1	16	0	0.0	0 00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
30 SUWANNEE	1-3	200	0	0.0	99 33	0.0	0	LIGHT OIL	0	BBLS		0	1,180	0 00
31 TURNER	1-4	199	0	0.0	0 00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0 00
32 OTHER & START UP		-	0	-	0 00	0.0	0	LIGHT OIL	2,801	BBLS	5.82	16,309	373,497	0 00
33 SOLAR		19	2,699		0 00	0.0	0	SOLAR	0	N/A		0	0	0 00
34 TOTAL			2,622,983									21,169,046	95,704,871	3 65

Docket No. 160001-EI
Schedule E4
Exh bit CAM-3, Part 2

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Dec-17

	(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	1	376	0	0.0	97.10	0.0	0	COAL	0	TONS	0.00	0	4,071	0.00
2	CRYSTAL RIVER	2	500	0	0.0	96.77	0.0	0	COAL	0	TONS	0.00	0	4,071	0.00
3	CRYSTAL RIVER	4	732	419,249	77.0	90.65	85.0	10,249	COAL	190,041	TONS	22.61	4,296,817	11,552,925	2.76
4	CRYSTAL RIVER	5	712	446,498	84.3	93.23	91.8	10,137	COAL	200,185	TONS	22.61	4,526,174	12,163,015	2.72
5	ANCLOTE	1	517	96,131	25.0	88.06	28.4	10,510	GAS	1,010,325	MCF	1.00	1,010,325	4,702,406	4.89
6	ANCLOTE	2	521	26,200	6.8	88.71	36.2	11,719	GAS	307,044	MCF	1.00	307,044	2,382,284	9.09
7	AVON PARK	1-2	69	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
8	BARTOW	1-4	228	0	0.0	81.13	0.0	0	GAS	0	MCF	0.00	0	0	0.00
9	BARTOW CC	1	1279	754,756	79.3	96.77	82.0	7,128	GAS	5,380,210	MCF	1.00	5,380,210	28,934,259	3.83
10	CITRUS CC	1-2	1586	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
11	DEBARY	1-10	785	116	0.0	96.32	16.8	12,457	GAS	1,445	MCF	1.00	1,445	7,766	6.69
12	HIGGINS	1-4	129	0	0.0	91.61	0.0	0	GAS	0	MCF	0.00	0	0	0.00
13	HINES CC	1-4	2,204	1,044,332	63.7	95.24	22.3	7,048	GAS	7,360,219	MCF	1.00	7,360,219	39,582,565	3.79
14	INT CITY	1-14	1,186	2,154	0.2	95.60	7.6	12,451	GAS	26,816	MCF	1.00	26,816	144,209	6.70
15	OSPREY CC	1	505	39,325	10.5	96.13	58.1	7,647	GAS	300,700	MCF	1.00	300,700	1,617,137	4.11
16	SUWANNEE STEAM	1	67	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
17	SUWANNEE STEAM	2	66	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
18	SUWANNEE STEAM	3	67	0	0.0	0.00	0.0	0	GAS	0	MCF	0.00	0	0	0.00
19	SUWANNEE CT	1-3	200	27	0.0	99.14	0.0	12,500	GAS	335	MCF	1.00	335	1,801	6.72
20	TIGER BAY CC	1	225	7,719	4.6	89.68	95.3	8,476	GAS	65,429	MCF	1.00	65,429	351,870	4.56
21	UNIV OF FLA. CC	1	47	34,675	99.2	97.10	102.2	9,428	GAS	326,912	MCF	1.00	326,912	1,758,101	5.07
22	AVON PARK	1-2	69	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
23	BARTOW	1-4	228	0	0.0	81.13	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
24	BAYBORO	1-4	231	0	0.0	95.97	0.0	0	LIGHT OIL	0	BBLS	0.00	0	96	0.00
25	DEBARY	1-10	785	16	0.0	96.32	0.0	14,088	LIGHT OIL	39	BBLS	5.74	224	6,537	41.11
26	HIGGINS	1-4	129	0	0.0	91.61	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
27	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
28	INT CITY	1-14	1,186	6	0.2	95.60	0.0	17,500	LIGHT OIL	18	BBLS	5.83	105	6,136	102.27
29	RIO PINAR	1	16	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
30	SUWANNEE	1-3	200	5	0.0	99.14	0.0	14,528	LIGHT OIL	13	BBLS	5.92	77	2,074	39.13
31	TURNER	1-4	199	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0.00	0	0	0.00
32	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	2,332	BBLS	5.83	13,585	341,226	0.00
33	SOLAR		19	2,644	18.7	0.00	0.0	0	SOLAR	0	N/A		0	0	0.00
34	TOTAL			2,873,853									23,616,417	103,562,549	3.60

Duke Energy Florida
Inventory Analysis
Estimated for the Period of : January through December 2017

	HEAVY OIL		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Subtotal
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	
11	UNIT COST	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	
12	AMOUNT	$	0	0	0	0	0	0	
	LIGHT OIL								
13	PURCHASES:								
14	UNITS	BBL	2,185	2,079	1,305	2,422	2,576	1,948	12,515
15	UNIT COST	$/BBL	153.97	159.28	216.81	146.23	141.69	167.18	159.43
16	AMOUNT	$	336,416	331,140	282,943	354,161	364,984	325,659	1,995,303
17	BURNED:								
18	UNITS	BBL	2,185	2,079	1,305	2,422	2,576	1,948	12,515
19	UNIT COST	$/BBL	153.97	159.28	216.81	146.23	141.69	167.18	159.43
20	AMOUNT	$	336,416	331,140	282,943	354,161	364,984	325,659	1,995,303
21	ENDING INVENTORY:								
22	UNITS	BBL	947,635	947,635	947,635	947,635	947,635	947,635	
23	UNIT COST	$/BBL	109.83	109.83	109.83	109.83	109.83	109.83	
24	AMOUNT	$	104,075,698	104,075,698	104,075,698	104,075,698	104,075,698	104,075,698	
	COAL								
25	PURCHASES:								
26	UNITS	TON	400,765	353,830	395,102	308,636	426,658	437,356	2,322,347
27	UNIT COST	$/TON	70.47	69.09	66.90	65.92	67.81	67.17	67.94
28	AMOUNT	$	28,240,918	24,446,219	26,430,916	20,346,221	28,929,952	29,375,644	157,769,870
29	BURNED:								
30	UNITS	TON	400,765	353,830	395,102	308,636	426,658	437,356	2,322,347
31	UNIT COST	$/TON	70.47	69.09	66.90	65.92	67.81	67.17	67.94
32	AMOUNT	$	28,240,918	24,446,219	26,430,916	20,346,221	28,929,952	29,375,644	157,769,870
33	ENDING INVENTORY:								
34	UNITS	TON	882,732	882,732	882,732	882,732	882,732	882,732	
35	UNIT COST	$/TON	70.47	69.09	66.90	65.92	67.81	67.17	
36	AMOUNT	$	62,203,917	60,988,219	59,051,593	58,192,342	59,854,526	59,289,931	
	GAS								
37	BURNED:								
38	UNITS	MCF	15,055,796	12,672,432	13,267,285	15,402,715	18,151,858	19,691,160	94,241,246
39	UNIT COST	$/MCF	4.51	4.55	4.61	4.20	4.30	4.14	4.36
40	AMOUNT	$	67,891,579	57,688,718	61,158,169	64,674,934	77,996,857	81,448,650	410,858,907
	NUCLEAR								
41	BURNED:								
42	UNITS	MMBTU	0	0	0	0	0	0	0
43	UNIT COST	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	AMOUNT	$	0	0	0	0	0	0	0

Duke Energy Florida
Inventory Analysis
Estimated for the Period of : January through December 2017

	HEAVY OIL		Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
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	
11	UNIT COST	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	
12	AMOUNT	$	0	0	0	0	0	0	
	LIGHT OIL								
13	PURCHASES:								
14	UNITS	BBL	1,394	2,581	2,630	1,061	2,839	2,402	25,422
15	UNIT COST	$/BBL	208.30	142.78	141.74	254.46	136.05	148.24	158.89
16	AMOUNT	$	290,364	368,505	372,783	269,987	386,250	356,069	4,039,261
17	BURNED:								
18	UNITS	BBL	1,394	2,581	2,630	1,061	2,839	2,402	25,422
19	UNIT COST	$/BBL	208.30	142.78	141.74	254.46	136.05	148.24	158.89
20	AMOUNT	$	290,364	368,505	372,783	269,987	386,250	356,069	4,039,261
21	ENDING INVENTORY:								
22	UNITS	BBL	947,635	947,635	947,635	947,635	947,635	947,635	
23	UNIT COST	$/BBL	109.83	109.83	109.83	109.83	109.83	109.83	
24	AMOUNT	$	104,075,698	104,075,698	104,075,698	104,075,698	104,075,698	104,075,698	
	COAL								
25	PURCHASES:								
26	UNITS	TON	480,852	475,901	444,791	299,087	294,557	390,226	4,707,761
27	UNIT COST	$/TON	66.46	66.01	65.54	62.58	61.51	60.80	66.03
28	AMOUNT	$	31,955,839	31,416,565	29,149,530	18,718,186	18,119,265	23,724,082	310,853,337
29	BURNED:								
30	UNITS	TON	480,852	475,901	444,791	299,087	294,557	390,226	4,707,761
31	UNIT COST	$/TON	66.46	66.01	65.54	62.58	61.51	60.80	66.03
32	AMOUNT	$	31,955,839	31,416,565	29,149,530	18,718,186	18,119,265	23,724,082	310,853,337
33	ENDING INVENTORY:								
34	UNITS	TON	882,732	882,732	882,732	882,732	882,732	882,732	
35	UNIT COST	$/TON	66.46	66.01	65.54	62.58	61.51	60.80	
36	AMOUNT	$	58,663,456	58,273,465	57,850,106	55,245,253	54,300,023	53,666,310	
	GAS								
37	BURNED:								
38	UNITS	MCF	20,336,850	20,743,588	19,200,406	18,089,452	14,492,163	14,779,435	201,883,140
39	UNIT COST	$/MCF	4.13	4.12	4.23	4.92	5.33	5.38	4.49
40	AMOUNT	$	83,894,763	85,369,629	81,228,339	88,912,548	77,199,356	79,482,398	906,945,940
	NUCLEAR								
41	BURNED:								
42	UNITS	MMBTU	0	0	0	0	0	0	0
43	UNIT COST	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	AMOUNT	$	0	0	0	0	0	0	0

Duke Energy Florida
Fuel Cost of Power Sold
Estimated for the Period of : January through December 2017

(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-17	ECONSALE	--	9,639		9,639	3.050	3.792	293,948	365,499	71,551
	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	--	62,957		62,957	2.545	2.545	1,602,253	1,602,253	0
	TOTAL		72,596		72,596	2.612	2.711	1,896,201	1,967,752	71,551
Feb-17	ECONSALE	--	7,068		7,068	2.734	3.400	193,248	240,286	47,038
	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	--	39,326		39,326	2.691	2.691	1,058,435	1,058,435	0
	TOTAL		46,394		46,394	2.698	2.799	1,251,683	1,298,721	47,038
Mar-17	ECONSALE	--	6,996		6,996	2.775	3.450	194,137	241,393	47,256
	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	--	70,645		70,645	2.538	2.538	1,793,288	1,793,288	0
	TOTAL		77,641		77,641	2.560	2.621	1,987,425	2,034,681	47,256
Apr-17	ECONSALE	--	9,610		9,610	3.392	4.218	325,957	405,297	79,340
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	84,368		84,368	2.392	2.392	2,017,970	2,017,970	0
	TOTAL		93,978		93,978	2.494	2.579	2,343,927	2,423,267	79,340
May-17	ECONSALE	--	7,349		7,349	3.329	4.140	244,693	304,253	59,560
	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	--	98,936		98,936	2.403	2.403	2,377,019	2,377,019	0
	TOTAL		106,285		106,285	2.467	2.523	2,621,712	2,681,272	59,560
Jun-17	ECONSALE	--	6,012		6,012	3.478	4.324	209,097	259,993	50,896
	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	--	101,407		101,407	2.413	2.413	2,446,981	2,446,981	0
	TOTAL		107,419		107,419	2.473	2.520	2,656,078	2,706,974	50,896

Duke Energy Florida
Fuel Cost of Power Sold
Estimated for the Period of : January through December 2017

(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-17	ECONSALE	--	3,548		3,548	3.233	4.020	114,697	142,616	27,919
	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	--	109,738		109,738	2.446	2.446	2,684,330	2,684,330	0
	TOTAL		113,286		113,286	2.471	2.495	2,799,027	2,826,946	27,919
Aug-17	ECONSALE	--	5,586		5,586	3.407	4.237	190,326	236,653	46,327
	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	--	109,823		109,823	2.462	2.462	2,703,432	2,703,432	0
	TOTAL		115,409		115,409	2.507	2.548	2,893,758	2,940,085	46,327
Sep-17	ECONSALE	--	2,645		2,645	3.085	3.836	81,602	101,466	19,864
	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	--	95,576		95,576	2.443	2.443	2,335,392	2,335,392	0
	TOTAL		98,221		98,221	2.461	2.481	2,416,994	2,436,858	19,864
Oct-17	ECONSALE	--	2,531		2,531	3.224	4.009	81,590	101,450	19,860
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	78,036		78,036	2.524	2.524	1,969,320	1,969,320	0
	TOTAL		80,567		80,567	2.546	2.570	2,050,910	2,070,770	19,860
Nov-17	ECONSALE	--	15,739		15,739	2.752	3.422	433,168	538,604	105,436
	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	--	45,057		45,057	2.684	2.684	1,209,264	1,209,264	0
	TOTAL		60,796		60,796	2.702	2.875	1,642,432	1,747,868	105,436
Dec-17	ECONSALE	--	5,981		5,981	2.572	3.198	153,818	191,259	37,441
	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	--	60,437		60,437	2.659	2.659	1,607,290	1,607,290	0
	TOTAL		66,418		66,418	2.652	2.708	1,761,108	1,798,549	37,441
Jan-17	ECONSALE	--	82,705		82,705	3.042	3.783	2,516,281	3,128,769	612,488
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-17	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	956,306		956,306	2.489	2.489	23,804,974	23,804,974	0
	TOTAL		1,039,011		1,039,011	2.533	2.592	26,321,255	26,933,743	612,488

Duke Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January through December 2017

(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-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	3,250			3,250	6.385	6.385	207,496
	SOCO Franklin	--	22,567			22,567	5.272	5.272	1,189,828
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	10,833			10,833	5.214	5.214	564,856
	TOTAL		36,650	0	0	36,650	5.354	5.354	1,962,180
Feb-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	275			275	6.995	6.995	19,251
	SOCO Franklin	--	15,271			15,271	6.190	6.190	945,243
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	1,723			1,723	6.261	6.261	107,876
	TOTAL		17,269	0	0	17,269	6.210	6.210	1,072,370
Mar-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	5,972			5,972	5.643	5.643	336,996
	SOCO Franklin	--	63,890			63,890	4.010	4.010	2,562,276
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	19,339			19,339	5.645	5.645	1,091,658
	TOTAL		89,202	0	0	89,202	4.474	4.474	3,990,930
Apr-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	8,574			8,574	4.815	4.815	412,846
	SOCO Franklin	--	75,078			75,078	3.539	3.539	2,657,010
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	34,203			34,203	5.346	5.346	1,828,375
	TOTAL		117,854	0	0	117,854	4.156	4.156	4,898,231
May-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	5,807			5,807	5.091	5.091	295,658
	SOCO Franklin	--	110,677			110,677	3.463	3.463	3,832,747
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	28,564			28,564	5.562	5.562	1,588,833
	TOTAL		145,048	0	0	145,048	3.942	3.942	5,717,238
Jun-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	14,566			14,566	5.028	5.028	732,425
	SOCO Franklin	--	153,256			153,256	3.333	3.333	5,107,530
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	59,554			59,554	5.339	5.339	3,179,402
	TOTAL		227,376	0	0	227,376	3.967	3.967	9,019,357
Jan-17	OTHER	--	0			0	0.000	0.000	0
THRU	Osprey (Calpine)	--	0			0	0.000	0.000	0
Jun-17	SHADY HILLS	--	38,445			38,445	5.214	5.214	2,004,672
	SOCO Franklin	--	440,739			440,739	3.697	3.697	16,294,634
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	154,216			154,216	5.422	5.422	8,361,000
	TOTAL		633,399	0	0	633,399	4.209	4.209	26,660,306

Duke Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January through December 2017

(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)
Jul-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	26,823			26,823	5.039	5.039	1,351,492
	SOCO Franklin	--	182,143			182,143	3.279	3.279	5,972,971
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	77,831			77,831	5.295	5.295	4,121,445
	TOTAL		286,797	0	0	286,797	3.991	3.991	11,445,908
Aug-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	30,474			30,474	5.013	5.013	1,527,661
	SOCO Franklin	--	187,079			187,079	3.273	3.273	6,122,439
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	92,746			92,746	5.290	5.290	4,906,438
	TOTAL		310,298	0	0	310,298	4.047	4.047	12,556,538
Sep-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	19,345			19,345	4.883	4.883	944,592
	SOCO Franklin	--	160,930			160,930	3.340	3.340	5,375,414
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	55,730			55,730	5.449	5.449	3,036,705
	TOTAL		236,004	0	0	236,004	3.965	3.965	9,356,711
Oct-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	19,526			19,526	5.701	5.701	1,113,093
	SOCO Franklin	--	160,577			160,577	3.318	3.318	5,327,370
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	57,109			57,109	6.214	6.214	3,548,867
	TOTAL		237,212	0	0	237,212	4.211	4.211	9,989,330
Nov-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	3,633			3,633	6.430	6.430	233,555
	SOCO Franklin	--	6,098			6,098	10.546	10.546	643,100
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	24,743			24,743	6.475	6.475	1,602,082
	TOTAL		34,474	0	0	34,474	7.190	7.190	2,478,737
Dec-17	OTHER	--	0			0	0.000	0.000	0
	Osprey (Calpine)	--	0			0	0.000	0.000	0
	SHADY HILLS	--	1,026			1,026	6.337	6.337	65,034
	SOCO Franklin	--	19,281			19,281	5.737	5.737	1,106,131
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	2,202			2,202	6.932	6.932	152,631
	TOTAL		22,509	0	0	22,509	5.881	5.881	1,323,796
Jan-17	OTHER	--	0			0	0.000	0.000	0
THRU	Osprey (Calpine)	--	0			0	0.000	0.000	0
Dec-17	SHADY HILLS	--	139,270			139,270	5.199	5.199	7,240,099
	SOCO Franklin	--	1,156,847			1,156,847	3.530	3.530	40,842,059
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	464,577			464,577	5.538	5.538	25,729,168
			1,760,693	0	0	1,760,693	4.192	4.192	73,811,326
TOTAL									

Duke Energy Florida
Energy Payments to Qualifying Facilities
Estimated for the Period of : January through December 2017

(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) ENERGY COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(A)
Jan-17	QUAL. FACILITIES	COGEN	296,006			296,006	4.114	12.213	12,177,556
Feb-17	QUAL. FACILITIES	COGEN	267,366			267,366	4.126	13.093	11,032,109
Mar-17	QUAL. FACILITIES	COGEN	270,166			270,166	4.376	13.250	11,823,009
Apr-17	QUAL. FACILITIES	COGEN	267,704			267,704	4.195	13.150	11,229,874
May-17	QUAL. FACILITIES	COGEN	286,889			286,889	4.206	12.563	12,066,147
Jun-17	QUAL. FACILITIES	COGEN	277,669			277,669	4.230	12.864	11,745,616
Jul-17	QUAL. FACILITIES	COGEN	286,942			286,942	4.252	12.607	12,199,522
Aug-17	QUAL. FACILITIES	COGEN	286,908			286,908	4.279	12.635	12,276,250
Sep-17	QUAL. FACILITIES	COGEN	277,650			277,650	4.282	12.917	11,889,369
Oct-17	QUAL. FACILITIES	COGEN	239,983			239,983	4.291	14.281	10,297,653
Nov-17	QUAL. FACILITIES	COGEN	276,511			276,511	4.141	12.811	11,450,142
Dec-17	QUAL. FACILITIES	COGEN	296,037			296,037	4.192	12.290	12,408,768
TOTAL	QUAL. FACILITIES	COGEN	3,329,832			3,329,832	4.222	12.862	140,596,014

Duke Energy Florida
Economy Energy Purchases
Estimated for the Period of : January through December 2017

(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-17	ECONPURCH	--	3,844	4.075	4.075	156,642	4.564	175,440	18,798
	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	-
	TOTAL		7,241	4.274	4.274	309,512	4.534	328,310	18,798
Feb-17	ECONPURCH	--	2,903	4.288	4.288	124,491	4.803	139,429	14,938
	SEPA	--	3,068	4.500	4.500	138,076	4.500	138,076	-
	TOTAL		5,971	4.397	4.397	262,567	4.647	277,505	14,938
Mar-17	ECONPURCH	--	7,273	4.058	4.058	295,167	4.545	330,587	35,420
	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	-
	TOTAL		10,670	4.199	4.199	448,037	4.531	483,457	35,420
Apr-17	ECONPURCH	--	4,308	4.580	4.580	197,301	5.130	220,977	23,676
	SEPA	--	3,288	4.500	4.500	147,938	4.500	147,938	-
	TOTAL		7,595	4.545	4.545	345,239	4.857	368,915	23,676
May-17	ECONPURCH	--	3,368	4.965	4.965	167,248	5.561	187,318	20,070
	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	-
	TOTAL		6,766	4.732	4.732	320,118	5.028	340,188	20,070
Jun-17	ECONPURCH	--	3,145	5.104	5.104	160,512	5.717	179,779	19,267
	SEPA	--	3,288	4.500	4.500	147,938	4.500	147,938	-
	TOTAL		6,432	4.795	4.795	308,450	5.095	327,717	19,267
Jan-17 THRU Jun-17	ECONPURCH	--	24,841	4.434	4.434	1,101,361	4.97	1,233,530	132,169
	SEPA	--	19,835	4.500	4.500	892,562	4.50	892,562	-
	TOTAL		44,676	4.463	4.463	1,993,923	4.759	2,126,092	132,169

Duke Energy Florida
Economy Energy Purchases
Estimated for the Period of : January through December 2017

(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-17	ECONPURCH	--	5,863	5.011	5.011	293,762	5.612	329,008	35,246
	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	-
	TOTAL		9,260	4.823	4.823	446,632	5.204	481,878	35,246
Aug-17	ECONPURCH	--	4,880	5.382	5.382	262,674	6.028	294,196	31,522
	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	-
	TOTAL		8,277	5.020	5.020	415,544	5.401	447,066	31,522
Sep-17	ECONPURCH	--	3,678	4.888	4.888	179,803	5.475	201,385	21,582
	SEPA	--	3,288	4.500	4.500	147,938	4.500	147,938	-
	TOTAL		6,966	4.705	4.705	327,741	5.015	349,323	21,582
Oct-17	ECONPURCH	--	9,939	4.575	4.575	454,696	5.124	509,270	54,574
	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	-
	TOTAL		13,336	4.556	4.556	607,566	4.965	662,140	54,574
Nov-17	ECONPURCH	--	5,010	4.135	4.135	207,190	4.632	232,057	24,867
	SEPA	--	3,288	4.500	4.500	147,938	4.500	147,938	-
	TOTAL		8,298	4.280	4.280	355,128	4.580	379,995	24,867
Dec-17	ECONPURCH	--	3,065	3.859	3.859	118,245	4.321	132,430	14,185
	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	-
	TOTAL		6,462	4.196	4.196	271,115	4.415	285,300	14,185
Jan-17 THRU Dec-17	ECONPURCH	--	57,276	4.570	4.570	2,617,731	5.119	2,931,876	314,145
	SEPA	--	39,998	4.500	4.500	1,799,918	4.500	1,799,918	-
	TOTAL		97,274	4.541	4.541	4,417,649	4.864	4,731,794	314,145

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Residential Bill Comparison
Estimated for the Period of : January 2017 *

	Current Nov-2016 * ($/1000 KWH)	Requested Jan-2017 * ($/1000 KWH)	Difference from Current $	Difference from Current %
Base Rate *	$58.99	$58.99	$0.00	0.00%
Fuel Cost Recovery	26.79	33.77	6.98	26.05%
Capacity Cost Recovery (CCR)	13.47	11.38	(2.09)	-15.52%
Energy Conservation Cost Recovery (ECCR)	3.25	3.17	(0.08)	-2.46%
Environmental Cost Recovery (ECRC)	1.84	1.51	(0.33)	-17.93%
Nuclear CR3 Uprate	1.76	1.56	(0.20)	-11.36%
Nuclear Levy	0.00	0.00	0.00	0.00%
Securitization	2.87	2.87	0.00	0.00%
Subtotal	108.97	113.25	4.28	3.93%
Gross Receipts Tax	2.79	2.90	0.11	3.94%
Total	$111.76	$116.15	$4.39	3.93%

* Nov-2016 Base Rate includes the $0.49 GBRA adjustment approved by the Commission at the August 9, 2016 Agenda. The Requested Jan-2017 does not include the GBRA Adjustment in DEF's petition filed in Docket 160178-EI. This adjustment, which includes the Osprey Combined Cycle Acquisition and Phase 2 of the Hines Chiller Uprate Project, will take effect with the February 2017 billing cycle. DEF has requested a GBRA adjustment of $1.50 on a 1,000kWh

Calculation of Inverted Residential Fuel Rates

	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	14,292,966	3.667	$ 524,123,082	3.377	$ 482,624,335
Over 1,000 kWh	5,847,726	3.667	214,436,105	4.377	255,934,852
Total	20,140,692		$ 738,559,187		$ 738,559,187
Rate Differential by Tier - Cents per kWh				1.000	

Residential Sales:	
Total	20,141,254
Time of Use	562
Levelized	20,140,692

Docket No. 160001-EI
Schedule H1
Exhibit CAM-3, Part 2

Duke Energy Florida
Generating System Comparative Data by Fuel Type

		2014 Actual	2015 Actual	2016 Actual / Estimated	2017 Projection	2015 vs. 2014	2016 vs. 2015	2017 vs. 2016
FUEL COST OF SYSTEM NET GENERATION ($)								
HEAVY OIL		0	0	0	0	0.0%	0.0%	0.0%
LIGHT OIL		21,114,159	20,687,452	11,112,027	4,039,261	-2.0%	-46.3%	-63.6%
COAL		479,549,089	379,954,861	314,437,587	310,853,337	-20.8%	-17.2%	-1.1%
GAS		1,053,354,312	947,933,972	806,113,993	906,945,940	-10.0%	-15.0%	12.5%
NUCLEAR		0	0	0	0	0.0%	0.0%	0.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	$	1,554,017,561	1,348,576,284	1,131,663,607	1,221,838,538	-13.2%	-16.1%	8.0%
SYSTEM NET GENERATION (MWH)								
HEAVY OIL		123,377	0	0	0	-100.0%	0.0%	0.0%
LIGHT OIL		35,150	72,848	37,730	529	107.2%	-48.2%	-98.6%
COAL		10,633,975	9,718,456	8,784,950	10,286,213	-8.6%	-9.6%	17.1%
GAS		23,066,236	25,227,323	24,915,809	26,700,833	9.4%	-1.2%	7.2%
NUCLEAR		0	0	0	0	0.0%	0.0%	0.0%
SOLAR		0	0	8,783	32,556	0.0%	0.0%	270.7%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	MWH	33,858,739	35,018,627	33,747,272	37,020,131	3.4%	-3.6%	9.7%
UNITS OF FUEL BURNED								
HEAVY OIL	BBL	250,994	0	0	0	-100.0%	0.0%	0.0%
LIGHT OIL	BBL	132,000	162,382	92,642	25,422	23.0%	-42.9%	-72.6%
COAL	TON	4,792,094	4,425,252	4,125,705	4,707,761	-7.7%	-6.8%	14.1%
GAS	MCF	177,503,510	198,464,799	195,915,062	201,883,140	11.8%	-1.3%	3.0%
NUCLEAR	MMBTU	0	0	0	0	0.0%	0.0%	0.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
BTUS BURNED (MMBTU)								
HEAVY OIL		1,529,500	0	0	0	-100.0%	0.0%	0.0%
LIGHT OIL		764,007	927,656	534,331	148,078	21.4%	-42.4%	-72.3%
COAL		111,597,504	102,196,707	93,826,406	106,890,768	-8.4%	-8.2%	13.9%
GAS		180,039,881	203,148,563	197,955,707	201,883,140	12.8%	-2.6%	2.0%
NUCLEAR		0	0	0	0	0.0%	0.0%	0.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	MMBTU	293,930,892	306,272,926	292,316,445	308,921,986	4.2%	-4.6%	5.7%
GENERATION MIX (% MWH)								
HEAVY OIL		0.36%	0.00%	0.00%	0.00%	-109.9%	0.0%	0.0%
LIGHT OIL		0.10%	0.21%	0.11%	0.00%	96.2%	-48.1%	-89.3%
COAL		31.41%	27.75%	26.03%	27.79%	-11.8%	-6.1%	6.9%
GAS		68.13%	72.04%	73.83%	72.13%	5.7%	2.5%	-2.3%
NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.0%	0.0%	0.0%
SOLAR		0.00%	0.00%	0.03%	0.09%	0.0%	0.0%	384.6%
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								
HEAVY OIL	$/BBL	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
LIGHT OIL	$/BBL	159.96	127.40	119.95	158.89	-20.4%	-5.9%	32.5%
COAL	$/TON	100.07	85.86	76.21	66.03	-14.2%	-11.2%	-13.4%
GAS	$/MCF	5.93	4.78	4.11	4.49	-19.5%	-13.9%	9.2%
NUCLEAR	$/MMBTU	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
FUEL COST PER MMBTU ($/MMBTU)								
HEAVY OIL		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
LIGHT OIL		27.64	22.30	20.80	27.28	-19.3%	-6.7%	31.2%
COAL		4.30	3.72	3.35	2.91	-13.5%	-9.9%	-13.2%
GAS		5.85	4.67	4.07	4.49	-20.3%	-12.7%	10.3%
NUCLEAR		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
TOTAL	$/MMBTU	5.29	4.40	3.87	3.96	-16.7%	-12.1%	2.2%
BTU BURNED PER KWH (BTU/KWH)								
HEAVY OIL		12,397	0	0	0	-100.0%	0.0%	0.0%
LIGHT OIL		21,735	12,734	14,162	280,079	-41.4%	11.2%	1877.7%
COAL		10,494	10,516	10,680	10,392	0.2%	1.6%	-2.7%
GAS		7,805	8,053	7,945	7,561	3.2%	-1.3%	-4.8%
NUCLEAR		0	0	0	0	0.0%	0.0%	0.0%
OTHER		0	0	0	0	0.0%	0.0%	0.0%
TOTAL	BTU/KWH	8,681	8,746	8,662	8,345	0.7%	-1.0%	-3.7%
GENERATED FUEL COST PER KWH (C/KWH)								
HEAVY OIL		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
LIGHT OIL		60.07	28.40	29.45	764.00	-52.7%	3.7%	2494.1%
COAL		4.51	3.91	3.58	3.02	-13.3%	-8.4%	-15.6%
GAS		4.57	3.76	3.24	3.40	-17.7%	-13.9%	5.0%
NUCLEAR		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
TOTAL	C/KWH	4.59	3.85	3.35	3.30	-16.1%	-12.9%	-1.6%

Docket 160001-EI
Exhibit No. ____(CAM-3)
Part 3

DUKE ENERGY FLORIDA

FUEL AND CAPACITY COST RECOVERY FACTOR

JANUARY THROUGH DECEMBER 2017

PART 3 – 2017 CAPACITY COST RECOVERY SCHEDULES

Schedule E12-A – Calculation of Projected Capacity Costs

Schedule E12-B – Calculation of Estimated/Actual 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
Calculation Projected Capacity Costs
For the Year 2017

Docket No. 160001-EI
Exhibit__CAM-3, Part 3
Schedule E12-A
Page 1 of 2

		EST Jan-17	EST Feb-17	EST Mar-17	EST Apr-17	EST May-17	EST Jun-17	EST Jul-17	EST Aug-17	EST Sep-17	EST Oct-17	EST Nov-17	EST Dec-17	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	60,858,768
3	Orlando Cogen Limited (ORLACOGL)	5,102,803	5,102,803	5,102,803	5,102,803	5,102,803	5,102,803	5,102,803	5,102,803	5,102,803	5,102,803	5,102,803	5,102,803	61,233,636
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)	6,965,674	6,965,674	6,965,674	6,965,674	6,965,674	6,965,674	6,965,674	6,965,674	6,965,674	6,965,674	6,965,674	6,965,674	83,588,088
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	9,611,352
8	Subtotal - Base Level Capacity Costs	23,974,387	23,974,387	23,974,387	23,974,387	23,974,387	23,974,387	23,974,387	23,974,387	23,974,387	23,974,387	23,974,387	23,974,387	287,692,644
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	22,268,609	22,268,608	22,268,608	22,268,608	22,268,608	22,268,609	22,268,609	22,268,609	22,268,609	22,268,609	22,268,609	22,268,609	267,223,307
11	**Intermediate Production Level Capacity Costs**													
12	Southern Franklin	4,565,768	4,565,768	2,682,208	2,682,208	2,951,288	5,158,612	6,250,556	6,250,556	4,612,640	2,701,738	2,701,738	3,520,696	48,643,776
13	Schedule H Capacity Sales - NSB	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Subtotal - Intermediate Level Capacity Costs	4,565,768	4,565,768	2,682,208	2,682,208	2,951,288	5,158,612	6,250,556	6,250,556	4,612,640	2,701,738	2,701,738	3,520,696	48,643,776
15	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%	
16	Intermediate Level Jurisdict. Capacity Costs	3,319,450	3,319,450	1,950,046	1,950,046	2,145,676	3,750,466	4,544,342	4,544,342	3,353,528	1,964,245	1,964,245	2,559,652	35,365,485
17	**Peaking Production Level Capacity Costs**													
18	Shady Hills	1,970,868	1,970,868	1,407,765	1,365,741	1,912,038	3,887,109	3,887,109	3,887,109	1,813,983	1,365,741	1,365,741	1,970,868	26,804,940
19	Vandolah (NSG)	2,777,276	2,792,868	2,001,752	1,979,480	2,699,316	5,565,668	5,548,960	5,504,412	2,634,348	1,940,500	1,985,048	2,792,868	38,222,496
20	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Subtotal - Peaking Level Capacity Costs	4,748,144	4,763,736	3,409,517	3,345,221	4,611,354	9,452,777	9,436,069	9,391,521	4,448,331	3,306,241	3,350,789	4,763,736	65,027,436
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	4,554,610	4,569,566	3,270,545	3,208,870	4,423,395	9,067,482	9,051,455	9,008,723	4,267,017	3,171,479	3,214,211	4,569,566	62,376,918
24	**Other Capacity Costs**													
25	Retail Wheeling	(16,864)	(12,365)	(12,240)	(16,811)	(12,857)	(10,518)	(6,207)	(9,772)	(4,627)	(4,427)	(27,535)	(10,464)	(144,689)
26	RRSSA Second Amendment [1]													
27	Batch-19 Nuclear Fuel [2]													
28	Total Other Capacity Costs													
29														
30	**Total Capacity Costs (line 10+16+23+28)**	31,918,164	31,933,653	29,261,390	29,191,180	30,601,326	36,848,579	37,626,777	37,576,516	31,645,178	29,156,593	29,172,254	31,079,186	386,010,796
31	Estimated/Actual True-Up Provision - Jan - Dec 2016													(14,665,234)
32	**Total Capacity Costs w/ True-Up**													371,345,562
33	Revenue Tax Multiplier													1.00072
34	**Total Recoverable Capacity Costs**													371,612,930
35	**Nuclear Cost Recovery Clause**													51,700,333
36	Revenue Tax Multiplier													1.00072
37	**Total Recoverable Nuclear Costs**													51,737,557
38	**ISFSI Revenue Requirement**													5,283,567
39	Revenue Tax Multiplier													1.00072
40	**Total Recoverable Nuclear Costs**													5,287,371
41	**Total Recov Capacity & Nuclear Costs (line 34+37+40)**													428,637,858

[1] Approved in Commission Order No. PSC-16-0138-FOF-EI
[2] Approved in Commission Order No. PSC-15-0465-S-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	74.00
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	Dec-23	QF	Purch	39.60
7	Florida Power Development	May-14	May-34	QF	Purch	60.00
8	Southern - Franklin	Jun-16	May-21	Other	Purch	425.00
9	Schedule H Capacity - New Smyrna Beach	Nov-85	see note (1)	Other	Sale	1.00
10	Chattahoochee	Jan-03	Dec-17	Other	Purch	5.25
11	Vandolah (NSG)	Jun-12	May-27	Other	Puch	655.00
12	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 DEF or NSB upon 1 year's written notice.

Duke Energy Florida
Calculation of Estimated/Actual True-up
For the Year 2016

Docket No. 160001-EI
Exhibit__CAM-3, Part 3
Schedule E12-B

		ACT Jan-16	ACT Feb-16	ACT Mar-16	ACT Apr-16	ACT May-16	ACT Jun-16	EST Jul-16	EST Aug-16	EST Sep-16	EST Oct-16	EST Nov-16	EST Dec-16	TOTAL
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	3,266,545	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	4,826,219	56,354,954
3	Orlando Cogen Limited (ORLACOGL)	13,409,604	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	4,854,074	66,804,417
4	Pasco County Resource Recovery (PASCOUNT)	1,577,570	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	1,677,850	20,033,920
5	Pinellas County Resource Recovery (PINCOUNT)	3,755,303	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	3,994,013	47,689,443
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	6,306,018	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	6,627,741	79,211,169
7	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	603,090	584,735	575,947	555,284	532,520	498,053	800,946	800,946	800,946	800,946	800,946	800,946	8,155,306
8	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Southern - Scherer	2,149,228	1,826,729	1,773,417	1,774,164	1,775,120	276,573	-	-	-	-	-	-	9,575,232
10	Calpine Osprey													
11	Subtotal - Base Level Capacity Costs													
12	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%	
13	Base Level Jurisdictional Capacity Costs													
14	**Intermediate Production Level Capacity Costs**													
15	Southern - Franklin	3,201,566	3,298,621	3,206,417	3,469,625	3,102,253	5,095,516	3,977,920	3,977,920	3,977,920	3,977,920	3,977,920	3,977,920	45,241,518
16	Schedule H Capacity Sales - NSB	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Subtotal - Intermediate Level Capacity Costs	3,201,566	3,298,621	3,206,417	3,469,625	3,102,253	5,095,516	3,977,920	3,977,920	3,977,920	3,977,920	3,977,920	3,977,920	45,241,518
19	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%	
20	Intermediate Level Jurisdictional Capacity Costs	2,327,635	2,398,196	2,331,161	2,522,522	2,255,431	3,704,593	2,892,067	2,892,067	2,892,067	2,892,067	2,892,067	2,892,067	32,891,940
21	**Peaking Production Level Capacity Costs**													
22	Chattahoochee	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Vandolah (RRI)	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Shady Hills Power Company LLC	1,410,667	1,671,610	1,406,700	1,366,200	1,886,760	3,855,600	3,887,109	3,887,109	1,813,983	1,365,741	1,365,741	1,970,868	25,888,088
25	Vandolah (NSG)	2,888,436	2,892,622	2,035,755	1,947,188	2,800,279	5,784,009	5,548,960	5,504,412	2,634,348	1,940,500	1,985,048	2,792,868	38,754,425
26	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Subtotal - Peaking Level Capacity Costs	4,299,103	4,564,232	3,442,455	3,313,388	4,687,039	9,639,609	9,436,069	9,391,521	4,448,331	3,306,241	3,350,789	4,763,736	64,642,513
28	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%	
29	Peaking Level Jurisdictional Capacity Costs	4,123,872	4,378,193	3,302,140	3,178,334	4,495,995	9,246,699	9,051,455	9,008,723	4,267,017	3,171,479	3,214,211	4,569,566	62,007,684
30	**Other Capacity Costs**													
31	Retail Wheeling	(33,737)	(1,790)	(6,527)	(149,519)	(1,545)	-	(10,552)	(9,520)	(3,987)	(3,672)	(13,683)	(6,532)	(241,063)
32	Batch 19 Nuclear Fuel													
33	Other Jurisdictional Capacity Costs													
34	**Subtotal Jurisd Capacity Costs (Line 13+20+29+33)**	36,845,611	31,001,440	29,795,934	29,701,997	30,880,285	35,657,755	34,628,864	34,587,164	29,850,991	28,755,768	28,788,489	30,092,937	380,587,235
35	**Nuclear Cost Recovery Clause Costs (net of tax)**													
36	Levy Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
37	CR3 Uprate Costs	4,861,279	4,833,013	4,804,746	4,776,479	4,748,212	4,719,946	4,691,679	4,663,412	4,635,145	4,606,878	4,578,612	4,550,345	56,469,745
38	**Total NCRC Costs - Order No. PSC-15-0586-FOF-EI**	4,861,279	4,833,013	4,804,746	4,776,479	4,748,212	4,719,946	4,691,679	4,663,412	4,635,145	4,606,878	4,578,612	4,550,345	56,469,745
39	**Total Jurisdictional Capacity Costs (Line 34+38)**	41,706,890	35,834,453	34,600,679	34,478,476	35,628,497	40,377,701	39,320,542	39,250,575	34,486,136	33,362,646	33,367,101	34,643,282	437,056,980
40	**Capacity Revenues**													
41	Capacity Cost Recovery Revenues (net of tax)	33,281,758	33,857,575	32,975,595	34,435,237	40,699,538	46,120,530	48,253,503	48,974,879	49,176,389	45,339,440	37,855,002	36,604,066	487,573,513
42	Prior Period True-Up Provision Over/(Under) Recovery	(3,220,271)	(3,220,271)	(3,220,271)	(2,900,148)	(2,900,139)	(2,900,139)	(2,900,139)	(2,900,139)	(2,900,139)	(2,900,139)	(2,900,139)	(2,900,135)	(35,762,070)
43	**Current Period Revenues (net of tax)**	30,061,487	30,637,304	29,755,324	31,535,089	37,799,399	43,220,391	45,353,364	46,074,740	46,276,250	42,439,301	34,954,863	33,703,931	451,811,442
44	**True-Up Provision**													
45	True-Up Provision - Over/(Under) Recov (Line 43-39)	(11,645,403)	(5,197,149)	(4,845,356)	(2,943,386)	2,170,902	2,842,690	6,032,821	6,824,164	11,790,113	9,076,655	1,587,762	(939,350)	14,754,463
46	Interest Provision for the Month	(13,312)	(15,364)	(16,922)	(15,793)	(13,154)	(12,389)	(4,367)	(2,860)	(584)	1,273	1,969	2,274	(89,229)
47	Current Cycle Balance - Over/(Under)	(11,658,715)	(16,871,228)	(21,733,506)	(24,692,684)	(22,534,936)	(19,704,635)	(13,676,181)	(6,854,877)	4,934,652	14,012,580	15,602,311	14,665,234	14,665,234
48	Prior Period Balance - Over/(Under) Recovered	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)	(35,762,070)
49	Prior Period Cumulative True-Up Collected/(Refunded)	3,220,271	6,440,543	9,660,814	12,560,962	15,461,101	18,361,240	21,261,379	24,161,518	27,061,657	29,961,796	32,861,935	35,762,070	35,762,070
50	Prior Period True-up Balance - Over/(Under)	(32,541,799)	(29,321,528)	(26,101,256)	(23,201,108)	(20,300,969)	(17,400,830)	(14,500,691)	(11,600,552)	(8,700,413)	(5,800,274)	(2,900,135)	(0)	(0)
51	**Net Capacity True-up Over/(Under) (Line 47+50)**	($44,200,514)	($46,192,755)	($47,834,762)	($47,893,792)	($42,835,905)	($37,105,465)	($28,176,872)	($18,455,429)	($3,765,761)	$8,212,306	$12,702,176	$14,665,234	$14,665,234

Duke Energy Florida
Calculation of Energy and Demand Percent by Rate Class
Using 12 CP & 1/13th AD Allocation Method for Production Demand
For the Year 2017

Docket No. 160001-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												**0.30%**
RS-1, RST-1, RSL-1, RSL-2, RSS-1												
Secondary	0.518	20,141,254	4,439.32	0.9467387	21,274,354	4,689.06	2,428.58	51.544%	61.523%	60.755%	1,115,172	3,335
General Service Non-Demand												
GS-1, GST-1												
Secondary	0.682	1,837,382	307.72	0.9467387	1,940,749	325.03	221.55	4.702%	4.265%	4.298%		
Primary	0.682	15,404	2.58	0.9762055	15,779	2.64	1.80	0.038%	0.035%	0.035%		
Transmission	0.682	3,081	0.52	0.9862055	3,124	0.52	0.36	0.008%	0.007%	0.007%		
								4.748%	4.306%	4.340%	100,920	302
General Service												
GS-2 Secondary	1.000	170,272	19.44	0.9467387	179,851	20.53	20.53	0.436%	0.269%	0.282%	3,539	11
General Service Demand												
GSD-1, GSDT-1												
Secondary	0.749	12,108,998	1,846.29	0.9467387	12,790,222	1,950.16	1,460.07	30.988%	25.587%	26.003%		
Transm Del/ Primary Mtr	0.749	3,326	0.51	0.9762055	3,407	0.52	0.39	0.008%	0.007%	0.007%		
Sec Del/Primary Mtr	0.749	46,857	7.14	0.9762055	47,999	7.32	5.48	0.116%	0.096%	0.098%		
Primary	0.749	2,302,950	351.14	0.9762055	2,359,083	359.70	269.30	5.716%	4.719%	4.796%		
SS-1 Primary	1.166	32,162	3.15	0.9762055	32,946	3.23	3.76	0.080%	0.042%	0.045%		
Transm Del/ Primary Mtr	1.166	2,282	0.22	0.9762055	2,338	0.23	0.27	0.006%	0.003%	0.003%		
Transmission	1.166	8,609	0.84	0.9862055	8,729	0.85	1.00	0.021%	0.011%	0.012%		
								36.935%	30.466%	30.963%	482,992	1,445
Curtailable												
CS-1, CST-1, CS-2, CST-2, SS-3												
Primary	1.305	81,904	7.16	0.9762055	83,900	7.34	9.58	0.203%	0.096%	0.105%		
SS-3 Primary	0.583	50,697	9.93	0.9762055	51,933	10.17	5.93	0.126%	0.133%	0.133%		
								0.329%	0.230%	0.237%	4,888	15
Interruptible												
IS-1, IST-1, IS-2, IST-2												
Secondary	1.009	87,039	9.84	0.9467387	91,936	10.40	10.49	0.223%	0.136%	0.143%		
Sec Del/Primary Mtr	1.009	4,421	0.50	0.9762055	4,529	0.51	0.52	0.011%	0.007%	0.007%		
Primary Del / Primary Mtr	1.009	1,321,165	149.41	0.9762055	1,353,368	153.05	154.49	3.279%	2.008%	2.106%		
Primary Del / Transm Mtr	1.009	425	0.05	0.9862055	431	0.05	0.05	0.001%	0.001%	0.001%		
Transm Del/ Primary Mtr	1.009	249,648	28.23	0.9762055	255,733	28.92	29.19	0.620%	0.379%	0.398%		
Transm Del/ Transm Mtr	1.009	268,068	30.32	0.9862055	271,818	30.74	31.03	0.659%	0.403%	0.423%		
SS-2 Primary	0.870	9,777	1.28	0.9762055	10,015	1.31	1.14	0.024%	0.017%	0.018%		
Transm Del/ Primary Mtr	0.870	72,672	9.54	0.9762055	74,443	9.77	8.50	0.180%	0.128%	0.132%		
Transmission	0.870	8,497	1.12	0.9862055	8,616	1.13	0.98	0.021%	0.015%	0.015%		
								5.017%	3.095%	3.243%	51,937	155
Lighting												
LS-1 (Secondary)	5.506	387,147	8.03	0.9467387	408,927	8.48	46.68	0.991%	0.111%	0.179%	8,442	25
Total		39,214,037	7,234.27		41,274,230	7,621.67	4,711.67	100.000%	100.000%	100.000%	1,767,890	5,287

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2015 (FPSC rule 25-6.0437 (7))
(2) Projected mWh sales for the period Jan-Dec 2017
(3) Calculated: Column 2 / (8,760 hours x Column 1)
(4) Based on system average line loss analysis for 2015
(5) Calculated: Column 2 / Column 4
(6) Calculated: Column 3 / Column 4
(7) Calculated: Column 5 / 8,760 hours
(8) Calculated: Column 7 / Total Column 7
(9) Calculated: Column 6 / Total Column 6
(10) Calculated: Column 8 x 1/13 + Column 9 x 12/13
(11) Projected Base Energy & Demand Revenues for Jan-Dec 2017
(12) Uniform Percent Calculated: Column 12 Total / Column 11 Total
Calculated: Column 11 x Uniform Percent

Duke Energy Florida
Calculation of Capacity Cost Recovery Factors by Rate Class
For the Year 2017

Docket No. 160001-EI
Exhibit__CAM-3, Part 3
Schedule E12-E
Page 1 of 2

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) Levy Production Demand Costs ($)	(6) CR3 Production Demand Costs ($)	(7) Capacity + Nuclear + ISFSI Production Demand Costs ($)	(8) Capacity CCR Factor (c/kWh)	(9) ISFSI CCR Factor (c/kWh)	(10) Levy CCR Factor (c/kWh)	(11) CR3 CCR Factor (c/kWh)	(12) Capacity & Nuclear CCR Factor (c/kWh)
Residential												
RS-1, RST-1, RSL-1, RSL-2, RSS-1												
Secondary	60.755%	20,141,254	$225,773,930	$3,335,234	$0	$31,433,222	$260,542,386	**1.121**	**0.017**	**0.000**	**0.156**	**1.294**
General Service Non-Demand												
GS-1, GST-1												
Secondary		1,837,382						**0.869**	**0.016**	**0.000**	**0.121**	**1.006**
Primary		15,250						**0.860**	**0.016**	**0.000**	**0.120**	**0.996**
Transmission		3,019						**0.852**	**0.016**	**0.000**	**0.119**	**0.986**
TOTAL GS	4.340%	1,855,651	16,128,410	301,829	0	2,245,467	18,675,706					
General Service												
GS-2 Secondary	0.282%	170,272	1,048,594	10,585	0	145,990	1,205,169	**0.616**	**0.006**	**0.000**	**0.086**	**0.708**
General Service Demand												
GSD-1, GSDT-1, SS-1												
Secondary		12,108,998										
Primary		2,363,701										
Transmission		8,437										
TOTAL GSD	30.963%	14,481,136	115,064,327	1,444,523	0	16,019,753	132,528,603					
Curtailable												
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3												
Secondary		-										
Primary		131,275										
Transmission		-										
TOTAL CS	0.237%	131,275	882,238	14,618	0	122,829	1,019,685					
Interruptible												
IS-1, IST-1, IS-2, IST-2, SS-2												
Secondary		87,039										
Primary		1,641,106										
Transmission		271,450										
TOTAL IS	3.243%	1,999,595	12,050,639	155,332	0	1,677,742	13,883,713					
Lighting												
LS-1 Secondary	0.179%	387,147	664,792	25,249	0	92,555	782,596	**0.172**	**0.007**	**0.000**	**0.024**	**0.203**
Total	100.000%	39,166,331	$371,612,930	$5,287,371	$0	$51,737,557	$428,637,858	**0.949**	**0.013**	**0.000**	**0.132**	**1.094**

Notes:

(1) From Schedule E12-D, Column 10
(2) Projected mWh sales at effective voltage level for Jan-Dec
(3) Column 1 x Total Recoverable Payments (Schedule E12-A)
(4) From Schedule E12-D, Column 12
(5) (Column 10 x Column 2) x 10
(6) Column 1 x Total Recoverable Payments (Schedule E12-A)
(7) Column 3 + Column 4 + Column 5 + Column 6
(8) (Column 3 / Column 2) / 10
(9) (Column 4 / Column 2) / 10
(10) (Column 5 / Column 2) / 10
(11) (Column 6 / Column 2) / 10
(12) Column 8 + Column 9 + Column 10 + Column 11
(13) Class Billing kW Load Factor
(14) Column 2 x 1000 / 8,760 / Column 13 x 12
(15) Column 3 / Column 14
(16) Column 4 / Column 14
(17) Column 5 / Column 14
(18) Column 6 / Column 14
(19) Column 7 / Column 14

Duke Energy Florida
Calculation of Capacity Cost Recovery Factors by Rate Class
For the Year 2017

Docket No. 160001-EI
Exhibit__CAM-3, Part 3
Schedule E12-E
Page 2 of 2

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) Levy Production Demand Costs ($)	(6) CR3 Production Demand Costs ($)	(7) Capacity + Nuclear + ISFSI Production Demand Costs ($)	(13) Billing KW Load Factor (%)	(14) Projected Effective KW at Meter Level (kW)	(15) Capacity CCR Factor ($/kW-mo)	(16) ISFSI CCR Factor ($/kW-mo)	(17) Levy CCR Factor ($/kW-mo)	(18) CR3 CCR Factor ($/kW-mo)	(19) Capacity & Nuclear CCR Factor ($/kW-mo)
Residential														
RS-1, RST-1, RSL-1, RSL-2, RSS-1														
Secondary	60.755%	20,141,254	$225,773,930	$3,335,234	$0	$31,433,222	$260,542,386							
General Service Non-Demand														
GS-1, GST-1														
Secondary		1,837,382												
Primary		15,250												
Transmission		3,019												
TOTAL GS	4.340%	1,855,651	16,128,410	301,829	0	2,245,467	18,675,706							
General Service														
GS-2 Secondary	0.282%	170,272	1,048,594	10,585	0	145,990	1,205,169							
General Service Demand														
GSD-1, GSDT-1, SS-1														
Secondary		12,108,998								**3.18**	**0.04**	**0.00**	**0.44**	**3.67**
Primary		2,363,701								**3.15**	**0.04**	**0.00**	**0.44**	**3.63**
Transmission		8,437								**3.12**	**0.04**	**0.00**	**0.43**	**3.60**
TOTAL GSD	30.963%	14,481,136	115,064,327	1,444,523	0	16,019,753	132,528,603	54.90%	36,133,284					
Curtailable														
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3														
Secondary		-								**2.50**	**0.04**	**0.00**	**0.35**	**2.89**
Primary		131,275								**2.48**	**0.04**	**0.00**	**0.35**	**2.86**
Transmission		-								**2.45**	**0.04**	**0.00**	**0.34**	**2.83**
TOTAL CS	0.237%	131,275	882,238	14,618	0	122,829	1,019,685	51.00%	352,605					
Interruptible														
IS-1, IST-1, IS-2, IST-2, SS-2														
Secondary		87,039								**2.46**	**0.03**	**0.00**	**0.34**	**2.83**
Primary		1,641,106								**2.44**	**0.03**	**0.00**	**0.34**	**2.80**
Transmission		271,450								**2.41**	**0.03**	**0.00**	**0.33**	**2.77**
TOTAL IS	3.243%	1,999,595	12,050,639	155,332	0	1,677,742	13,883,713	55.90%	4,900,128					
Lighting														
LS-1 Secondary	0.179%	387,147	664,792	25,249	0	92,555	782,596							
Total	100.000%	39,166,331	$371,612,930	$5,287,371	$0	$51,737,557	$428,637,858							

Notes:

(1) From Schedule E12-D, Column 10
(2) Projected mWh sales at effective voltage level for Jan-Dec
(3) Column 1 x Total Recoverable Payments (Schedule E12-A)
(4) From Schedule E12-D, Column 12
(5) (Column 10 x Column 2) x 10
(6) Column 1 x Total Recoverable Payments (Schedule E12-A)
(7) Column 3 + Column 4 + Column 5 + Column 6
(8) (Column 3 / Column 2) / 10
(9) (Column 4 / Column 2) / 10
(10) (Column 5 / Column 2) / 10
(11) (Column 6 / Column 2) / 10
(12) Column 8 + Column 9 + Column 10 + Column 11
(13) Class Billing kW Load Factor
(14) Column 2 x 1000 / 8,760 / Column 13 x 12
(15) Column 3 / Column 14
(16) Column 4 / Column 14
(17) Column 5 / Column 14
(18) Column 6 / Column 14
(19) Column 7 / Column 14

***Calculation of Standby Service kW Charges:**

	Capacity + Nuclear Cost Cost	Effective kW	$/kW
Total GSD, CS, IS	$147,432,001	41,386,017	3.56
SS-1, 2, 3 - $/kW-mo	Secondary	Primary	Trans
Monthly - $3.56/kW * 10%	0.356	0.352	0.349
Daily - $3.56/kW / 21	0.170	0.168	0.167

APPENDIX I

FUEL COST RECOVERY

2015 FINAL TRUE UP CALCULATION

TJK-1
DOCKET NO. 160001-EI
FPL WITNESS: TERRY J. KEITH
PAGES 1-6
EXHIBIT ____
MARCH 2, 2016

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 18
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT & SUPPLEMENTAL)*Notice of Adoption of Terry

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP

FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

	Total
1. End of Period True-up [1]	($37,050,993)
2. Less: Actual Estimated True-up for the same period [2]	($66,818,243)
3. Net True-up for the period	$29,767,250

[1] Page 2, Column (14) Lines 40 & 41.

[2] Approved in FPSC Final Order PSC-15-0586-FOF-EI.

Note: Totals may not add due to rounding.

( ) Reflects Underrecovery

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF FINAL TRUE-UP AMOUNT

SCHEDULE: E1-B

FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

Line No.	(1)	(2) January Actual	(3) February Actual	(4) March Actual	(5) April Actual	(6) May Actual	(7) June Actual	(8) July Actual	(9) August Actual	(10) September Actual	(11) October Actual	(12) November Actual	(13) December Actual	(14) 12 Month Period
1	**Fuel Costs & Net Power Transactions**													
2	Fuel Cost of System Net Generation (Per A3) [1]	$246,664,759	$216,161,869	$257,084,388	$277,829,341	$281,801,536	$301,524,023	$303,259,051	$311,136,907	$297,318,972	$278,842,946	$253,493,993	$235,457,687	$3,260,575,473
3	Scherer Coal Cars Depreciation & Return (Per A2)	$0	$0	($53,435)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($53,435)
4	Cedar Bay – Rail Coal Cars Lease per Docket No. 150075-EI	$0	$0	$0	$0	$0	$0	$0	$0	$114,014	$121,164	$131,064	$114,014	$480,256
5	Fuel Cost of Power Sold (Per A6)	($16,429,924)	($15,976,225)	($6,686,080)	($748,351)	($2,230,166)	($1,625,793)	($1,882,916)	($1,875,924)	($1,283,252)	($2,159,877)	($1,911,102)	($3,595,024)	($56,404,635)
6	Gains from Off-System Sales (Per A6)	($8,278,889)	($9,725,531)	($3,166,550)	($332,482)	($767,361)	($554,966)	($590,851)	($517,102)	($435,049)	($580,636)	($519,488)	($1,329,134)	($26,798,039)
7	Fuel Cost of Purchased Power (Per A7)	$7,435,276	$9,097,205	$9,977,819	$9,894,170	$18,878,007	$20,637,329	$23,648,179	$25,710,657	$22,068,137	$22,780,978	$20,212,605	$7,997,614	$198,337,975
8	Energy Payments to Qualifying Facilities (Per A8)	$1,327,108	$1,083,118	$980,587	$7,244,956	$10,248,362	$11,774,346	$10,151,103	$10,252,365	$8,536,509	$5,582,280	($1,312,571)	$1,469,027	$67,337,191
9	Energy Cost of Economy Purchases (Per A9)	$0	$145,000	$1,294,660	$2,398,817	$1,358,485	$4,329,015	$2,390,635	$4,065,346	$3,521,110	$688,296	$1,758,821	$282,244	$22,232,429
10	Total Fuel Costs & Net Power Transactions	$230,718,330	$200,785,437	$259,431,389	$296,286,452	$309,288,863	$336,083,954	$336,975,202	$348,772,248	$329,840,441	$305,275,151	$271,853,321	$240,396,428	$3,465,707,215
11														
12	**Incremental Optimization Costs**													
13	Incremental Personnel, Software, and Hardware Costs (Per A2)	$37,399	$34,067	$44,881	$35,301	$33,614	$34,538	$32,298	$61,710	$34,940	$45,280	$38,911	$40,610	$473,550
14	Variable Power Plant O&M Costs over 514,000 MWH Threshold (Per A6)	$157,809	$888,185	$438,890	$73,170	$127,879	$89,921	$92,895	$89,567	$69,730	$112,098	$103,347	$320,433	$2,563,924
15	Total	$195,208	$922,252	$483,771	$108,471	$161,493	$124,459	$125,193	$151,277	$104,670	$157,378	$142,259	$361,043	$3,037,474
16														
17	Dodd Frank Fees	$375	$375	$375	$375	$375	$375	$375	$384	$375	$375	$375	$375	$4,509
18														
19	**Adjustments to Fuel Cost**													
20	Energy Imbalance Fuel Revenues	($101,562)	($129,818)	($52,136)	($79,012)	($134,841)	($90,157)	($105,407)	($105,834)	($129,837)	($80,182)	($6,372)	($50,826)	($1,065,982)
21	Inventory Adjustments	($349,002)	$271,182	($16,541)	$40,609	($52,902)	($2,589)	$88,955	($107,475)	($166,518)	($167,187)	($125,538)	($135,886)	($722,889)
22	Non Recoverable Oil/Tank Bottoms	($1,347,774)	$810,620	$0	$0	$1,085,377	$0	($47,633)	$0	($242,422)	$365,686	$0	$0	$623,854
23	Adjusted Total Fuel Costs & Net Power Transactions	$229,115,575	$202,660,049	$259,846,859	$296,356,894	$310,348,365	$336,116,043	$337,036,685	$348,710,601	$329,406,709	$305,551,222	$271,864,045	$240,571,134	$3,467,584,181
24	**Jurisdictional kWh Sales**													
25	Jurisdictional kWh Sales	7,954,413,052	7,113,174,773	7,752,924,515	8,634,798,845	9,380,232,035	10,001,639,015	10,763,691,577	10,646,987,154	10,480,394,526	9,413,964,298	9,095,762,441	8,582,416,040	109,820,398,271
26	Sales for Resale	385,765,418	453,052,199	446,421,902	534,432,568	588,536,338	590,679,241	620,086,673	676,411,420	651,800,570	580,885,920	555,873,117	526,088,422	6,610,033,788
27	Sub-Total Sales	8,340,178,470	7,566,226,972	8,199,346,417	9,169,231,413	9,968,768,373	10,592,318,256	11,383,778,250	11,323,398,574	11,132,195,096	9,994,850,218	9,651,635,558	9,108,504,462	116,430,432,059
28														
29	**Jurisdictional % of Total Sales (Line 25/27)**	95.37461%	94.01218%	94.55540%	94.17146%	94.09620%	94.42351%	94.55289%	94.02643%	94.14491%	94.18815%	94.24063%	94.22421%	94.32276%
30	**True-up Calculation**													
31	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$266,828,804	$237,417,940	$259,488,001	$291,742,132	$292,351,504	$313,631,073	$340,620,984	$336,176,556	$330,158,043	$293,622,838	$281,980,985	$263,928,764	$3,507,947,625
32	**Fuel Adjustment Revenues Not Applicable to Period**													
33	Prior Period True-up (Collected)/Refunded This Period [2]	($22,221,724)	($22,221,724)	($22,221,724)	($22,221,724)	($22,221,724)	($22,221,724)	($22,221,724)	($22,221,724)	($22,221,724)	($22,221,724)	($22,221,724)	($22,221,724)	($266,660,688)
34	GPIF, Net of Revenue Taxes [3]	($983,868)	($983,868)	($983,868)	($983,868)	($983,868)	($983,868)	($983,868)	($983,868)	($983,868)	($983,868)	($983,868)	($983,868)	($11,806,416)
35	Midcourse correction - Prior Period True-up (Collected)/Refunded This Period	$0	$0	$0	$0	$1,261,105	$1,261,105	$1,261,105	$1,261,105	$1,261,105	$1,261,105	$1,261,105	$1,261,105	$10,088,837
36	Jurisdictional Fuel Revenues Applicable to Period	$243,623,212	$214,212,348	$236,282,409	$268,536,540	$270,407,016	$291,686,586	$318,676,497	$314,232,068	$308,213,556	$271,678,350	$260,036,497	$241,984,276	$3,239,569,357
37	Adjusted Total Fuel Costs & Net Power Transactions	$229,115,575	$202,660,049	$259,846,859	$296,356,894	$310,348,365	$336,116,043	$337,036,685	$348,710,601	$329,406,709	$305,551,222	$271,864,045	$240,571,134	$3,467,584,181
38	Jurisdictional Sales % of Total kWh Sales (Line 29)	95.37461%	94.01218%	94.55540%	94.17146%	94.09620%	94.42351%	94.55289%	94.02643%	94.14491%	94.18815%	94.24063%	94.22421%	94.32276%
39	Juris. Total Fuel Costs & Net Power Trans. (Line 37xLine38x1.00169)	$218,887,382	$190,847,118	$246,114,468	$279,555,266	$292,566,266	$317,959,704	$319,267,480	$328,486,707	$310,693,371	$288,325,460	$256,680,371	$227,095,602	$3,276,479,195
40	True-up Provision for the Month - Over/(Under) Recovery (Line 36 - Line 39)	$24,735,831	$23,365,231	($9,832,059)	($11,018,725)	($22,159,250)	($26,273,118)	($590,983)	($14,254,639)	($2,479,815)	($16,647,110)	$3,356,127	$14,888,675	($36,909,838)
41	Interest Provision for the Month	($19,417)	($14,798)	($11,840)	($9,130)	($9,411)	($10,827)	($10,837)	($11,307)	($11,073)	($10,351)	($9,567)	($12,598)	($141,155)
42	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	($266,660,688)	($219,722,550)	($174,150,393)	($161,772,568)	($150,578,700)	($151,786,741)	($157,110,066)	($136,751,268)	($130,056,595)	($111,586,864)	($107,283,706)	($82,976,526)	($266,660,688)
43	Deferred True-up Beginning of Period - Over/(Under) Recovery [4]	$10,088,837	$10,088,837	$10,088,837	$10,088,837	$10,088,837	$10,088,837	$10,088,837	$10,088,837	$10,088,837	$10,088,837	$10,088,837	$10,088,837	$10,088,837
44	Prior Period True-up Collected/(Refunded) This Period [2]	$22,221,724	$22,221,724	$22,221,724	$22,221,724	$22,221,724	$22,221,724	$22,221,724	$22,221,724	$22,221,724	$22,221,724	$22,221,724	$22,221,724	$266,660,688
45	Midcourse correction - 2014 final true-up collected/(refunded) this period	$0	$0	$0	$0	($1,261,105)	($1,261,105)	($1,261,105)	($1,261,105)	($1,261,105)	($1,261,105)	($1,261,105)	($1,261,105)	($10,088,837)
46	End of Period Net True-up Amount Over/(Under) Recovery (Lines 40 through 45)	($209,633,713)	($164,061,556)	($151,683,731)	($140,489,863)	($141,697,904)	($147,021,229)	($126,662,431)	($119,967,758)	($101,498,027)	($97,194,869)	($72,887,689)	($37,050,993)	($37,050,993)
47	% Net (Under)/Over Recovery													
48														
49	[1] Actuals include various adjustments as noted on the A-Schedules.													
50	[2] Prior Period 2013/2014 True-up.													
51	[3] Generating Performance Incentive Factor is ((11,814,923 / 12) x 99.9280%) - See Order No. PSC-14-0701-FOF-EI.													
52	[4] 2014 Final True-up.													
53														
54	Note: Amounts may not agree to Actual/Estimated Filing or A-Schedules due to rounding.													
55														

FLORIDA POWER & LIGHT COMPANY
REVENUE/COST VARIANCE ANALYSIS

FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

Line No.	(1) Revenue/Cost Final Variance Analysis	(2) Final True-up	(3) Actual Estimated	(4) DIFFERENCE
1	**Jurisdictional Total Fuel Revenues**			
2	Revenues	$3,507,947,625	$3,475,069,359	$32,878,266
3	MWH	109,820,398	108,830,936	989,462
4	$ per MWH	31.94259	31.93090	0.01169
5				
6	Variance due to Consumption			$31,594,423
7	Variance due to Price			$1,283,843
8	Total Variance			$32,878,266
9				
10	**Jurisdictional Total Fuel Costs**			
11	Costs	$3,276,479,195	$3,273,379,599	$3,099,597
12	MWH	109,820,398	108,830,936	989,462
13	$ per MWH	29.83489	30.07766	(0.24277)
14				
15	Variance due to Consumption			$29,760,713
16	Variance due to Price			($26,661,116)
17	Total Variance			$3,099,597
18				
19	**Total Variance**			
20	Variance due to Consumption			$1,833,710
21	Variance due to Price			$27,944,959
22	Total Variance			$29,778,669
23	Interest			($11,419)
24	Total True-up			$29,767,250
25				
26				
27	( ) Reflects Underrecovery			
28				
29	Note: Totals may not add down due to rounding.			
30				
31				
32				
33				
34				
35				
36				
37				

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF VARIANCE - FINAL TRUE-UP VS. ACTUAL/ESTIMATED TRUE-UP

FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

Line No.	(1)	(2) FCR - 2015 Final True-up	(3) FCR - 2015 Actual/Estimated - Supplemental Filing	(4) Dif. FCR - 2015 Actual/Estimated - Supplemental Filing	(5) % Dif. FCR - 2015 Actual/Estimated - Supplemental Filing
1	**Fuel Costs & Net Power Transactions**				
2	Fuel Cost of System Net Generation (Per A3)	$3,260,575,473	$3,267,287,262	($6,711,789)	(0.2%)
3	Scherer Coal Cars Depreciation & Return (Per A2)	($53,435)	($53,435)	$0	0.0%
4	Cedar Bay – Rail Coal Cars Lease per Docket No. 150075-EI	$480,256	$452,360	$27,896	6.2%
5	Fuel Cost of Power Sold (Per A6)	($56,404,635)	($62,352,934)	$5,948,298	(9.5%)
6	Gains from Off-System Sales (Per A6)	($26,798,039)	($28,331,630)	$1,533,591	(5.4%)
7	Fuel Cost of Purchased Power (Per A7)	$198,337,975	$184,538,649	$13,799,326	7.5%
8	Energy Payments to Qualifying Facilities (Per A8)	$67,337,191	$74,604,104	($7,266,913)	(9.7%)
9	Energy Cost of Economy Purchases (Per A9)	$22,232,429	$17,225,175	$5,007,255	29.1%
10	Total Fuel Costs & Net Power Transactions	$3,465,707,215	$3,453,369,551	$12,337,665	0.4%
11					
12	**Incremental Optimization Costs**				
13	Incremental Personnel, Software, and Hardware Costs (Per A2)	$473,550	$441,826	$31,723	7.2%
14	Variable Power Plant O&M Costs over 514,000 MWH Threshold (Per A6)	$2,563,924	$2,759,649	($195,725)	(7.1%)
15	Total	$3,037,474	$3,201,475	($164,002)	(5.1%)
16					
17	Dodd Frank Fees	$4,509	$4,500	$9	0.2%
18					
19	**Adjustments to Fuel Cost**				
20	Energy Imbalance Fuel Revenues	($1,065,982)	($692,933)	($373,049)	53.8%
21	Inventory Adjustments	($722,889)	$1,065,091	($1,787,980)	(167.9%)
22	Non Recoverable Oil/Tank Bottoms	$623,854	($584,787)	$1,208,641	(206.7%)
23	Adjusted Total Fuel Costs & Net Power Transactions	$3,467,584,181	$3,456,362,897	$11,221,284	0.3%
24	**Jurisdictional kWh Sales**				
25	Jurisdictional kWh Sales	109,820,398,271	108,830,935,816	989,462,455	0.9%
26	Sales for Resale	6,610,033,788	6,284,038,295	325,995,493	5.2%
27	Sub-Total Sales	116,430,432,059	115,114,974,111	1,315,457,948	1.1%
28					
29	**Jurisdictional % of Total Sales (Line 25/27)**	N/A	N/A	N/A	N/A
30	**True-up Calculation**				
31	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$3,507,947,625	$3,475,069,359	$32,878,266	0.9%
32	**Fuel Adjustment Revenues Not Applicable to Period**				
33	Prior Period True-up (Collected)/Refunded This Period [2]	($266,660,688)	($266,660,688)	$0	0.0%
34	GPIF, Net of Revenue Taxes [1]	($11,806,416)	($11,806,416)	($0)	0.0%
35	Midcourse correction - Prior Period True-up (Collected)/Refunded This Period	$10,088,837	$10,088,837	$0	0.0%
36	Jurisdictional Fuel Revenues Applicable to Period	$3,239,569,357	$3,206,691,092	$32,878,266	1.0%
37	Adjusted Total Fuel Costs & Net Power Transactions	$3,467,584,181	$3,456,362,897	$11,221,284	0.3%
38	Jurisdictional Sales % of Total kWh Sales (Line 29)	N/A	N/A	N/A	N/A
39	Juris. Total Fuel Costs & Net Power Trans. (Line 37xLine38x1.00169)	$3,276,479,195	$3,273,379,599	$3,099,597	0.1%
40	True-up Provision for the Month - Over/(Under) Recovery (Line 36 - Line 39)	($36,909,838)	($66,688,507)	$29,778,669	(44.7%)
41	Interest Provision for the Month	($141,155)	($129,736)	($11,419)	8.8%
42	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	($266,660,688)	($266,660,688)	$0	0.0%
43	Deferred True-up Beginning of Period - Over/(Under) Recovery [3]	$10,088,837	$10,088,837	$0	0.0%
44	Prior Period True-up Collected/(Refunded) This Period [2]	$266,660,688	$266,660,688	$0	0.0%
45	Midcourse correction - 2014 final true-up collected/(refunded) this period	($10,088,837)	($10,088,837)	$0	0.0%
46	End of Period Net True-up Amount Over/(Under) Recovery (Lines 40 through 45)	($37,050,993)	($66,818,243)	$29,767,250	(44.5%)
47					
48	[1] Generating Performance Incentive Factor is ((11,814,923 / 12) x 99.9280%) - See Order No. PSC-14-0701-FOF-EI.				
49	[2] Prior Period 2013/2014 Net True-up.				
50	[3] 2014 Final True-up.				
51					
52	Note: Amounts may not agree to A-Schedules due to rounding.nding.				
53					

Florida Power & Light Company
Fuel and Purchased Power Recovery Clause
For the Period January through June 2015

Return on Capital Investments & Depletion
For Project: Gas Reserves Investment
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Capital addition		$0	$0	$34,111,238	$9,356,775	$16,063,203	$11,514,793	$71,046,008
									$0
2.	Gas Reserve Investment / DD&A Base (A)	$0	$0	$0	$34,111,238	$43,468,013	$59,531,216	$71,046,008	n/a
3.	Less: Accumulated Depletion Reserve	$0	$0	$0	$237,136	$315,464	$409,385	$694,142	n/a
3a	Net Working Capital Adjustment		$0	$0	$12,465,807	$9,113,672	$22,599,196	$13,799,010	
									n/a
4.	Net Investment & Net Working Capital (Lines 2 - 3)	$0	$0	$0	$46,339,909	$52,266,220	$81,721,026	$84,150,877	n/a
5.	Average Rate Base		$0	$0	$23,169,955	$49,303,065	$66,993,623	$82,935,952	n/a
6.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		$0	$0	$154,651	$329,080	$447,158	$553,567	$1,484,455
	b. Debt Component (Line 5 x debt rate x 1/12) (C)		$0	$0	$28,483	$60,608	$82,355	$101,953	$273,400
	Subtotal (Debt & Equity Return)		$0	$0	$183,134	$389,688	$529,513	$655,520	$1,757,855
7.	Investment and Operating Expenses								
	a. Transportation Costs		$0	$0	$48,162	$26,402	$36,050	$141,530	$252,145
	b. Depletion		$0	$0	$106,015	$78,329	$93,921	$284,756	$563,021
	c. Lease Operating Expenses (LOE)		$0	$0	$24,000	$95,829	($2,375)	$510,203	$627,657
	d. Taxes (Ad-Valorem, Severance & Franchise)		$0	$0	$1,561	$961	$1,330	$5,994	$9,847
	e. G&A		$0	$0	$99,231	$64,291	$37,847	$47,107	$248,476
	f. Insurance		$0	$0	$0	$0	$0	$0	$0
	g Accretion expense				$158	$158	$158	$1,060	$1,534
	Subtotal Expenses		$0	$0	$279,127	$265,971	$166,931	$990,650	$1,702,680
8.	Total System Recoverable Expenses (Lines 6 & 7a-f)		$0	$0	$462,261	$655,659	$696,444	$1,646,171	$3,460,534

Notes:

(A) Applicable beginning of period and end of period DD&A (Depreciation, Depletion & Amortization) base

(B) The gross-up factor for taxes uses 0.6110, which reflects the Federal Income Tax Rate of 35% and Oklahoma State Tax rate of 6%.
The monthly Equity Component is 4.8938% based on the May 2014 Earnings Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(C) The debt component is 1.4751% based on the May 2014 Earnings Surveillance Report and reflects a 10.5% ROE, per FPSC Order No. PSC-12-0425-PAA-EU.

Totals may not add due to rounding.

Florida Power & Light Company
Fuel and Purchased Power Recovery Clause
For the Period July through December 2015

Return on Capital Investments & Depletion
For Project: Gas Reserves Investment
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	Sept Actual	Oct Actual	Nov Actual	Dec Actual	Project To Date Amount
1.	Investments								
	a. Capital addition		20,378,046	20,434,075	11,738,814	10,971,728	11,236,212	4,947,134	150,752,017
									0
2.	Gas Reserve Investment / DD&A Base (A)	71,046,008	91,424,055	111,858,129	123,596,943	134,568,671	145,804,882	150,752,017	n/a
3.	Less: Accumulated Depletion Reserve	694,142	1,635,794	2,741,492	3,740,737	5,064,272	6,421,591	8,216,025	n/a
3a	Net Working Capital Adjustment	13,799,010	36,799,185	35,883,992	46,696,444	65,490,867	58,848,082	60,073,404	
									n/a
4.	Net Investment & Net Working Capital (Lines 2 - 3)	84,150,877	126,587,446	145,000,629	166,552,650	194,995,265	198,231,373	202,609,396	n/a
5.	Average Rate Base		105,369,162	135,794,037	155,776,639	180,773,957	196,613,319	200,420,385	n/a
6.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		692,712	892,729	1,024,098	1,188,433	1,292,564	1,317,592	7,892,583
	b. Debt Component (Line 5 x debt rate x 1/12) (C)		130,868	168,656	193,475	224,521	244,194	248,922	1,484,036
	Subtotal (Debt & Equity Return)		823,580	1,061,385	1,217,572	1,412,955	1,536,757	1,566,514	9,376,619
7.	Investment and Operating Expenses								
	a. Transportation Costs		(616,438)	0	0	0	0	0	(364,294)
	b. Depletion		941,652	1,105,698	999,245	1,323,535	1,357,319	1,794,434	8,084,904
	c. Lease Operating Expenses (LOE)		469,529	1,964,517	959,778	1,200,668	1,484,879	1,130,962	7,837,989
	d. Taxes (Ad-Valorem, Severance & Franchise)		10,720	23,068	20,329	73,702	34,653	41,077	213,395
	e. G&A		62,407	121,301	3,440	46,066	16,130	39,789	537,610
	f. Insurance		0	0	0	0	0	0	0
	g Accretion expense		1,963	1,316	1,316	1,579	1,842	2,105	11,655
	Subtotal Expenses		869,833	3,215,900	1,984,108	2,645,550	2,894,824	3,008,367	16,321,261
8.	Total System Recoverable Expenses (Lines 6 & 7a-f)		1,693,413	4,277,286	3,201,680	4,058,505	4,431,581	4,574,881	25,697,879

Notes:

(A) Applicable beginning of period and end of period DD&A (Depreciation, Depletion & Amortization) base

(B) The gross-up factor for taxes uses 0.6110, which reflects the Federal Income Tax Rate of 35% and Oklahoma State Tax rate of 6%.
The monthly Equity Component is 4.8201% based on the May 2015 Earnings Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(C) The debt component is 1.4904% based on the May 2015 Earnings Surveillance Report and reflects a 10.5% ROE, per FPSC Order No. PSC-12-0425-PAA-EU.

Totals may not add due to rounding.

APPENDIX II

CAPACITY COST RECOVERY

2015 FINAL TRUE UP CALCULATION

TJK-2
DOCKET NO. 160001-EI
FPL WITNESS: TERRY J. KEITH
PAGES 1-13
EXHIBIT ____
MARCH 2, 2016

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 19
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT & SUPPLEMENTAL)*Notice of Adoption of Terry

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP
FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

Line No.		Dec - 2015
1	End of Period True-up for the period [1]	$13,638,140
2	Less - Estimated/Actual True-up for the same period [2]	$7,699,316
3	Net True-up for the period	$5,938,824
4		
5	[1] From Page 2, Column (14), Lines 21 & 22.	
6	[2] Approved in FPSC Final Order PSC-15-0586-FOF-EI.	
7		
8	Note: Totals may not add due to rounding	
9		
10	( ) Reflects Under-recovery	
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
FOR THE PERIOD JANUARY 2015 THROUGH DECEMBER 2015

Line No.	(1)	(2) January Actual	(3) February Actual	(4) March Actual	(5) April Actual	(6) May Actual	(7) June Actual	(8) July Actual	(9) August Actual	(10) September Actual	(11) October Actual	(12) November Actual	(13) December Actual	(14) Total
1	Payments to Non-cogenerators	$13,911,366	$13,975,636	$14,787,778	$14,454,872	$14,700,342	$14,214,737	$14,120,489	$16,115,162	$15,293,202	$15,204,846	$15,508,268	$15,122,007	$177,408,704
2	Payments to Cogenerators	$24,606,259	$23,681,563	$24,046,776	$24,070,465	$24,019,465	$24,136,932	$22,979,348	$22,923,072	$18,122,974	$11,834,751	$11,483,597	$11,674,925	$243,580,129
3	Cedar Bay Transaction - Regulatory Asset - Amortization and Return	$0	$0	$0	$0	$0	$0	$0	$0	$8,009,572	$9,673,705	$9,643,449	$9,613,192	$36,939,918
4	Cedar Bay Transaction - Regulatory Liability - Amortization and Return	$0	$0	$0	$0	$0	$0	$0	$0	($90,469)	($117,510)	($117,018)	($116,527)	($441,525)
5	SJRPP Suspension Accrual	($743,251)	($743,251)	($743,251)	($798,207)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($9,083,880)
6	Return on SJRPP Suspension Liability	($289,443)	($283,595)	($277,746)	($271,682)	($265,563)	($259,607)	($250,837)	($244,947)	($239,057)	($233,166)	($227,276)	($221,385)	($3,064,304)
7	Incremental Plant Security Costs O&M	$3,177,518	$2,591,941	$3,147,376	$3,089,619	$2,703,690	$2,665,806	$2,681,167	$3,060,846	$3,164,332	$3,345,602	$3,167,721	$4,045,681	$36,841,299
8	Incremental Plant Security Costs Capital	$70,318	$77,424	$84,955	$91,364	$98,236	$105,624	$111,502	$116,950	$121,204	$125,139	$132,777	$144,995	$1,280,489
9	Incremental Nuclear NRC Compliance Costs O&M	$10,625	($18,529)	$27,148	$44,475	$44,957	$23,307	$30,946	$108,537	$31,947	$64,087	$28,322	$2,038,598	$2,434,420
10	Incremental Nuclear NRC Compliance Costs Capital	$213,101	$236,464	$264,834	$315,967	$350,674	$375,683	$398,877	$432,258	$461,144	$498,095	$551,725	$584,361	$4,683,184
11	Transmission of Electricity by Others	$2,363,793	$2,030,739	$2,207,794	$1,924,530	$1,397,123	$153,447	$2,137,731	($239,274)	$1,073,502	$1,607,613	$1,510,291	$2,253,101	$18,420,391
12	Transmission Revenues from Capacity Sales	($988,891)	($1,255,218)	($735,254)	($116,851)	($260,934)	($224,295)	($79,619)	($141,896)	($91,831)	($290,629)	($170,646)	($577,434)	($4,933,499)
13	Total (Lines 1 through 12)	$42,331,395	$40,293,174	$42,810,409	$42,804,553	$42,031,001	$40,434,645	$41,372,614	$41,373,717	$45,099,530	$40,955,544	$40,754,220	$43,804,525	$504,065,326
14	Jurisdictional Separation Factor [(a)]	94.64598%	94.64598%	94.64598%	94.64598%	94.64598%	94.64598%	94.64598%	94.64598%	94.64598%	94.64598%	94.64598%	94.64598%	N/A
15	Jurisdictional CCR Charges	$40,064,964	$38,135,870	$40,518,331	$40,512,789	$39,780,652	$38,269,766	$39,157,516	$39,158,560	$42,684,892	$38,762,776	$38,572,231	$41,459,222	$477,077,567
16	Nuclear Cost Recovery Costs [(a)]	$828,412	$904,960	$1,199,655	$1,003,858	$1,264,329	$1,173,932	$975,723	$953,036	$1,246,085	$922,340	$940,085	$2,875,446	$14,287,862
17	Jurisdictional CCR Charges	$40,893,376	$39,040,830	$41,717,986	$41,516,646	$41,044,982	$39,443,698	$40,133,239	$40,111,596	$43,930,977	$39,685,116	$39,512,316	$44,334,668	$491,365,430
18	CCR Revenues (Net of Revenue Taxes)	$35,066,176	$32,198,366	$35,135,669	$38,287,814	$41,255,187	$43,630,802	$46,807,087	$46,210,004	$45,733,568	$41,593,703	$40,154,892	$37,565,871	$483,639,140
19	Prior Period True-up Provision	$1,779,447	$1,779,447	$1,779,447	$1,779,447	$1,779,447	$1,779,447	$1,779,447	$1,779,447	$1,779,447	$1,779,447	$1,779,447	$1,779,447	$21,353,369
20	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$36,845,624	$33,977,814	$36,915,117	$40,067,261	$43,034,634	$45,410,250	$48,586,535	$47,989,451	$47,513,015	$43,373,151	$41,934,340	$39,345,318	$504,992,509
21	True-up Provision for Month - Over/(Under) Recovery (Line 20 - Line 17)	($4,047,752)	($5,063,016)	($4,802,870)	($1,449,385)	$1,989,652	$5,966,552	$8,453,296	$7,877,855	$3,582,038	$3,688,035	$2,422,024	($4,989,349)	$13,627,079
22	Interest Provision for Month	$1,290	$725	$183	($154)	($265)	($133)	$290	$921	$1,400	$1,652	$1,927	$3,224	$11,060
23	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	$21,353,369	$15,527,459	$8,685,721	$2,103,587	($1,125,399)	($915,459)	$3,271,513	$9,945,651	$16,044,979	$17,848,969	$19,759,208	$20,403,712	$21,353,369
24	Deferred True-up - Over/(Under) Recovery	($2,951,171)	($2,951,171)	($2,951,171)	($2,951,171)	($2,951,171)	($2,951,171)	($2,951,171)	($2,951,171)	($2,951,171)	($2,951,171)	($2,951,171)	($2,951,171)	($2,951,171)
25	Prior Period True-up Provision - Collected/(Refunded) this Month	($1,779,447)	($1,779,447)	($1,779,447)	($1,779,447)	($1,779,447)	($1,779,447)	($1,779,447)	($1,779,447)	($1,779,447)	($1,779,447)	($1,779,447)	($1,779,447)	($21,353,369)
26	End of Period True-up - Over/(Under) Recovery (Sum of Lines 21 through 25)	$12,576,288	$5,734,550	($847,584)	($4,076,570)	($3,866,630)	$320,342	$6,994,480	$13,093,808	$14,897,798	$16,808,037	$17,452,541	$10,686,969	$10,686,969
27														
28	[(a)] As approved on Order No PSC-14-0701-FOF-EI.													
29														
30	Total may not add due to rounding													
31														
32														
33														
34														
35														
36														
37														

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

Line No.	CCR - Final True-up Variance	(1) CCR - 2015 Final True-up	(2) CCR - 2015 Actual/Estimated True-up - Supplemental Filing	(3) Dif. CCR - 2015 Actual/Estimated True-up - Supplemental Filing	(4) % Dif. CCR - 2015 Actual/Estimated True-up - Supplemental Filing
1	Payments to Non-cogenerators	$177,408,704	$176,195,951	$1,212,753	0.7%
2	Payments to Cogenerators	$243,580,129	$244,996,833	($1,416,704)	(0.6%)
3	Cedar Bay Transaction - Regulatory Asset - Amortization and Return	$36,939,918	$36,939,917	$1	0.0%
4	Cedar Bay Transaction - Regulatory Liability - Amortization and Return	($441,525)	($441,523)	($1)	0.0%
5	SJRPP Suspension Accrual	($9,083,880)	($9,083,880)	$0	0.0%
6	Return on SJRPP Suspension Liability	($3,064,304)	($3,064,304)	$0	0.0%
7	Incremental Plant Security Costs O&M	$36,841,299	$38,685,065	($1,843,766)	(4.8%)
8	Incremental Plant Security Costs Capital	$1,280,489	$1,359,932	($79,443)	(5.8%)
9	Incremental Nuclear NRC Compliance Costs O&M	$2,434,420	$991,859	$1,442,561	145.4%
10	Incremental Nuclear NRC Compliance Costs Capital	$4,683,184	$4,636,627	$46,557	1.0%
11	Transmission of Electricity by Others	$18,420,391	$21,012,049	($2,591,658)	(12.3%)
12	Transmission Revenues from Capacity Sales	($4,933,499)	($5,193,563)	$260,064	(5.0%)
13	Total (Lines 1 through 12)	$504,065,326	$507,034,963	($2,969,637)	(0.6%)
14	Jurisdictional Separation Factor [(a)]	94.64598%	94.64598%	0.00000%	(0.0%)
15	Jurisdictional CCR Charges	$477,077,567	$479,888,209	($2,810,642)	(0.6%)
16	Nuclear Cost Recovery Costs [(a)]	$14,287,862	$14,287,861	$1	0.0%
17	Jurisdictional CCR Charges	$491,365,430	$494,176,070	($2,810,641)	(0.6%)
18	CCR Revenues (Net of Revenue Taxes)	$483,639,140	$480,515,710	$3,123,430	0.7%
19	Prior Period True-up Provision	$21,353,369	$21,353,369	$0	0.0%
20	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$504,992,509	$501,869,079	$3,123,430	0.6%
21	True-up Provision for Month - Over/(Under) Recovery (Line 20 - Line 17)	$13,627,079	$7,693,009	$5,934,070	77.1%
22	Interest Provision for Month	$11,060	$6,307	$4,753	75.4%
23	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	$21,353,369	$21,353,369	$0	0.0%
24	Deferred True-up - Over/(Under) Recovery	($2,951,171)	($2,951,171)	$0	0.0%
25	Prior Period True-up Provision - Collected/(Refunded) this Month	($21,353,369)	($21,353,369)	$0	0.0%
26	End of Period True-up - Over/(Under) Recovery (Sum of Lines 21 through 25)	$10,686,969	$4,748,145	$5,938,824	125.1%
27					
28	[(a)] As approved on Order No. PSC-14-0701-FOF-EI.				
29					
30	Columnns and rows may not add due to rounding				
31					
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Florida Power & Light Company
Schedule A12 - Capacity Costs
Page 1 of 2

For the Month of **Dec-15**

Contract	Capacity MW	Term Start	Term End	Contract Type
Cedar Bay	250	1/25/1994	9/18/2015	QF
Indiantown	330	12/22/1995	12/1/2025	QF
Broward North - 1991 Agreement	11	1/1/1993	11/3/2015	QF
Broward South - 1991 Agreement	3.5	1/1/1993	12/31/2026	QF
SWAPC	40	1/1/2012	3/31/2032	QF

QF = Qualifying Facility

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
Cedar Bay	11,529,146	10,579,222	10,957,049	10,980,738	10,948,658	11,019,465	10,972,681	10,941,640	6,223,874	-35,479	3,976		94,120,971
ICL	11,566,193	11,591,421	11,578,807	11,578,807	11,559,887	11,569,347	11,569,347	11,544,111	11,556,729	11,556,729	11,582,001	11,569,365	138,822,747
BN-NEG '91	331,760	331,760	331,760	331,760	331,760	331,760	331,760	331,760	236,810	207,941	-207,941		2,890,890
BS-NEG '91	105,560	105,560	105,560	105,560	105,560	105,560	105,560	105,560	105,560	105,560	105,560	105,560	1,266,720
SWAPC	1,073,600	1,073,600	1,073,600	1,073,600	1,073,600	1,110,800							6,478,800
Total	24,606,259	23,681,563	24,046,776	24,070,465	24,019,465	24,136,932	22,979,348	22,923,072	18,122,974	11,834,751	11,483,597	11,674,925	243,580,129

Florida Power & Light Company
Schedule A12 - Capacity Costs
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For the Month of Dec-15

Contract	Counterparty	Identification	Contract Start Date	Contract End Date
1	Southern Co. - UPS Scherer	Other Entity	June, 2010	December 31, 2015
2	Southern Co. - UPS Harris	Other Entity	June, 2010	December 31, 2015
3	Southern Co. - UPS Franklin	Other Entity	June, 2010	December 31, 2015
4	JEA - SJRPP	Other Entity	April, 1982	September 30, 2021
5	Solid Waste Authority - 40 MW	Other Entity	January, 2012	March 31, 2032
6	Solid Waste Authority - 70 MW	Other Entity	July, 2015	May 31, 2034

2015 Capacity in MW

Contract	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	163	163	163	163	163	163	163	163	163	163	163	163
2	600	600	600	600	600	600	600	600	600	600	600	600
3	190	190	190	190	190	190	190	190	190	190	190	190
4	375	375	375	375	375	375	375	375	375	375	375	375
5	-	-	-	-	-	-	40	40	40	40	40	40
6	-	-	-	-	-	-	70	70	70	70	70	70
Total	1,328	1,328	1,328	1,328	1,328	1,328	1,438	1,438	1,438	1,438	1,438	1,438

2015 Capacity in Dollars

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total	13,911,366	13,975,636	14,787,777	14,454,872	14,700,342	14,214,737	15,231,289	15,004,362	15,293,201	15,204,846	15,508,268	15,122,007

Year-to-date Short Term Capacity Payments	177,408,703 [(1)]

Contract	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1												
2												
3												
4												
5												
6												

True ups												
1												
2												
3												
4												
5												
6												

(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.

Florida Power & Light Company
Capacity Cost Recovery Clause
For the Period January through June 2015

Return on Capital Investments, Depreciation and Taxes
Incremental Security
(in Dollars)

Line		Beginning of Period Amount	Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$533,192	$711,059	$764,985	$906,003	$967,901	$921,446	$4,804,585
	b. Clearings to Plant		$850	$375,545	$445,961	($97,044)	$43	($0)	$725,355
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other		$0	$11,592	$0	$0	$0	$0	$11,592
2.	Plant-In-Service/Depreciation Base	$525,932	$526,782	$902,327	$1,348,288	$1,251,244	$1,251,287	$1,251,287	n/a
3.	Less: Accumulated Depreciation	$2,333	$6,806	$23,685	$29,306	$35,189	$41,000	$46,810	n/a
4.	CWIP - Non Interest Bearing	$7,579,710	$8,112,902	$8,823,961	$9,142,984	$10,048,987	$11,016,888	$11,938,334	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$8,103,308	$8,632,878	$9,702,603	$10,461,966	$11,265,042	$12,227,176	$13,142,811	n/a
10.	Average Net Investment		$8,368,093	$9,167,741	$10,082,285	$10,863,504	$11,746,109	$12,684,993	n/a
11.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (a)		$55,558	$60,868	$66,939	$72,126	$77,986	$84,220	$417,697
	b. Debt Component (Line 6 x debt rate x 1/12) (b)		$10,287	$11,270	$12,394	$13,355	$14,439	$15,594	$77,339
12.	Investment Expenses								
	a. Depreciation		$4,472	$5,287	$5,622	$5,883	$5,810	$5,811	$32,885
	b. Amortization		$0	$0	$0	$0	$0	$0	$0
	c. Other		$0	$0	$0	$0	$0	$0	$0
13.	Total System Recoverable Expenses (Lines 11 & 12)		$70,318	$77,424	$84,955	$91,364	$98,236	$105,624	$527,921

Notes:

[a] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component is 4.89380%, which is based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[b] The Debt Component is 1.4751%, which is based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

Totals may not add due to rounding.

Florida Power & Light Company
Capacity Cost Recovery Clause
For the Period July through December 2015

Return on Capital Investments, Depreciation and Taxes
Incremental Security
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
a.	Expenditures/Additions		$599,427	$487,301	($1,554,805)	$446,867	$391,570	$452,959	$5,627,905
b.	Clearings to Plant		$239,956	$32,915	$1,773,861	$34,340	$373,606	$504,577	$3,684,610
c.	Retirements		$0	$0	$0	$0	$0	$0	$0
d.	Other		$0	$0	$623	$0	$0	$0	$12,215
2.	Plant-In-Service/Depreciation Base (a)	$1,251,287	$1,491,243	$1,524,158	$3,298,019	$3,332,359	$3,705,965	$4,210,542	n/a
3.	Less: Accumulated Depreciation	$46,810	$52,801	$58,997	$67,251	$76,158	$87,935	$105,341	n/a
4.	CWIP - Non Interest Bearing	$11,938,335	$12,537,762	$13,025,062	$11,470,258	$11,917,125	$12,308,695	$12,761,654	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$13,142,811	$13,976,204	$14,490,224	$14,701,026	$15,173,326	$15,926,725	$16,866,855	n/a
10.	Average Net Investment		$13,559,508	$14,233,214	$14,595,625	$14,937,176	$15,550,025	$16,396,790	n/a
11.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (a)		$88,670	$93,076	$95,446	$97,680	$101,687	$107,224	$1,001,481
b.	Debt Component (Line 6 x debt rate x 1/12) (b)		$16,841	$17,678	$18,128	$18,552	$19,313	$20,365	$188,215
12.	Investment Expenses								
a.	Depreciation		$5,991	$6,196	$7,631	$8,907	$11,777	$17,406	$90,793
b.	Amortization		$0	$0	$0	$0	$0	$0	$0
c.	Other		$0	$0	$0	$0	$0	$0	$0
13.	Total System Recoverable Expenses (Lines 11 & 12)		$111,502	$116,950	$121,204	$125,139	$132,777	$144,995	$1,280,489

Notes:

(a) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component is 4.8201%, which is based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(b) The Debt Component is 1.4904%, which is based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

Totals may not add due to rounding.

Florida Power & Light Company
Capacity Cost Recovery Clause
For the Period January through June 2015

Return on Capital Investments, Depreciation and Taxes
Incremental Nuclear NRC Compliance
(in Dollars)

Line		Beginning of Period Amount	Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	Six Month Amount
1.	Investments								
a.	Expenditures/Additions		($4,750,125)	$971,278	$3,744,012	($3,057,848)	$1,153,739	$525,471	($1,413,473)
b.	Clearings to Plant		$3,918,699	$777,775	$776,878	$7,746,695	$1,242,449	$2,549,709	$17,012,204
c.	Clearings to Plant - Base		4,056,793	$0	$0	$0	$0	$0	$4,056,793
c.	Retirements		$0	$0	$0	$0	$0	$0	$0
d.	Other		$0	$0	$0	$19,279	$993	$3,343	$23,615
2.	Incremental Plant-In-Service/Depreciation Base (a) (f)	$0	$3,918,699	$4,696,473	$5,473,351	$13,220,047	$14,462,495	$17,012,204	
3.	Less: Accumulated Depreciation	$0	$3,251	$10,335	$21,191	$66,447	$100,561	$140,800	
4.	CWIP - Non Interest Bearing	$29,114,970	$24,364,845	$25,336,123	$29,080,135	$26,022,287	$27,176,026	$27,701,497	
5.	Net Investment (Lines 2 - 3 + 4)	$29,114,970	$28,280,293	$30,022,261	$34,532,295	$39,175,886	$41,537,961	$44,572,901	n/a
6.	Total Estimated Capital Expenditures Included in Base Rates (b)	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	
7.	Base Rate Capital Expenditures Closed to Plant-in-Service (c) (g)	$5,943,207	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	
8.	Remaining Amount Included in Base Rates (Lines 6 - 7)	$4,056,793	$0	$0	$0	$0	$0	$0	
9.	Adjusted Net Investment (Lines 5 - 8)	$25,058,177	$28,280,293	$30,022,261	$34,532,295	$39,175,886	$41,537,961	$44,572,901	
10.	Average Net Investment		$26,669,235	$29,151,277	$32,277,278	$36,854,091	$40,356,924	$43,055,431	n/a
11.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (d)		$177,065	$193,545	$214,299	$244,686	$267,942	$285,859	$1,383,396
b.	Debt Component (Line 6 x debt rate x 1/12) (e)		$32,784	$35,836	$39,678	$45,305	$49,611	$52,928	$256,142
12.	Investment Expenses								
a.	Depreciation		$3,251	$7,084	$10,856	$25,977	$33,120	$36,897	$117,185
b.	Amortization		$0	$0	$0	$0	$0	$0	$0
c.	Other		$0	$0	$0	$0	$0	$0	$0
13.	Total System Recoverable Expenses (Lines 11 & 12)		$213,101	$236,464	$264,834	$315,967	$350,674	$375,683	$1,756,723

Notes:

(a) Represents nuclear NRC compliance plant-in-service in excess of the total estimated capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI) on line 6.

(b) Represents forecasted nuclear NRC compliance capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI).

(c) Represents base rate recoverable nuclear NRC compliance capital expenditures closed to plant-in-service.

(d) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component is 4.8938%, which is based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(e) The Debt Component is 1.4751%, which is based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(f) The April 2015 Incremental Plant-In-Service balance was restated to adjust the return on investment for a transfer of a St. Lucie Unit 2 participant work order to properly reflect the net investment balance.

(g) The January 2015 beginning balance does not agree to the December 2014 ending balance due to the correction of a work order classification from clause to base made during 2015.

Totals may not add due to rounding.

Florida Power & Light Company
Capacity Cost Recovery Clause
For the Period July through December 2015

Return on Capital Investments, Depreciation and Taxes
Incremental Nuclear NRC Compliance
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		($2,228,713)	$85,502	$204,260	($4,378,858)	($11,294,994)	$1,000,637	($18,025,639)
	b. Clearings to Plant		$4,955,071	$3,815,338	$1,852,055	$8,894,249	$15,214,073	$326,942	$52,069,931
	c. Clearings to Plant - Base		$0	$0	$0	$0	$0	$0	$4,056,793
	d. Retirements		$0	$0	$0	$0	$0	$0	$0
	e. Other		$0	$3,694	$0	$0	$4,292	$0	$31,600
2.	Incremental Plant-In-Service/Depreciation Base (a) (f)	$17,012,204	$21,967,275	$25,782,612	$27,634,667	$36,528,916	$51,742,989	$52,069,931	n/a
3.	Less: Accumulated Depreciation	$140,800	$182,394	$235,647	$291,340	$358,894	$452,180	$554,156	n/a
4.	CWIP - Non Interest Bearing	$27,701,497	$25,472,784	$25,558,286	$25,762,546	$21,383,688	$10,088,694	$11,089,331	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$44,572,901	$47,257,665	$51,105,251	$53,105,873	$57,553,711	$61,379,503	$62,605,106	n/a
6.	Total Estimated Capital Expenditures Included in Base Rates (b)	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	
7.	Base Rate Capital Expenditures Closed to Plant-in-Service (c) (g)	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	
8.	Remaining Amount Included in Base Rates (Lines 6 - 7)	$0	$0	$0	$0	$0	$0	$0	
9.	Adjusted Net Investment (Lines 5 - 8)	$44,572,901	$47,257,665	$51,105,251	$53,105,873	$57,553,711	$61,379,503	$62,605,106	
10.	Average Net Investment	$22,286,450	$45,915,283	$49,181,458	$52,105,562	$55,329,792	$59,466,607	$61,992,304	n/a
11.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (d)		$300,256	$321,615	$340,737	$361,821	$388,873	$405,390	$3,502,089
	b. Debt Component (Line 6 x debt rate x 1/12) (e)		$57,027	$61,083	$64,715	$68,720	$73,858	$76,994	$658,539
12.	Investment Expenses								
	a. Depreciation		$41,594	$49,560	$55,693	$67,554	$88,994	$101,977	$522,556
	b. Amortization		$0	$0	$0	$0	$0	$0	$0
	c. Other		$0	$0	$0	$0	$0	$0	$0
13.	Total System Recoverable Expenses (Lines 11 & 12)		$398,877	$432,258	$461,144	$498,095	$551,725	$584,361	$4,683,184

Notes:

(a) Represents nuclear NRC compliance plant-in-service in excess of the total estimated capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI) on line 6.

(b) Represents forecasted nuclear NRC compliance capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI).

(c) Represents base rate recoverable nuclear NRC compliance capital expenditures closed to plant-in-service.

(d) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component is 4.8201%, which is based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(e) The Debt Component is 1.4751%, which is based on the May 2014 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

(f) The April 2015 Incremental Plant-In-Service balance was restated to adjust the return on investment for a transfer of a St. Lucie Unit 2 participant work order to properly reflect the net investment balance.

(g) The January 2015 beginning balance does not agree to the December 2014 ending balance due to the correction of a work order classification from clause to base made during 2015.

Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY

CEDAR BAY TRANSACTION

Regulatory Asset Related to the Loss of the PPA and Income Tax Gross-Up (Amortization and Return Calculation)

For the Period January through December 2015

Line No.	Description	Beginning of Period	January	February	March	April	May	June	July	August	September	October	November	December	Total	Line. No.
1	Regulatory Asset - Loss of PPA		-	-	-	-	-	-	-	-	$ 435,500,000	$ 431,611,607	$ 427,723,214	$ 423,834,821	n/a	1
2	Regulatory Asset - Loss of PPA Amort		-	-	-	-	-	-	-	-	3,888,393	3,888,393	3,888,393	3,888,393	$ 15,553,572	2
3	Unamortized Regulatory Asset - Loss of PPA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 431,611,607	$ 427,723,214	$ 423,834,821	$ 419,946,428	n/a	3
4	Average Unamortized Regulatory Asset - Loss of PPA		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 215,805,804	$ 429,667,411	$ 425,779,018	$ 421,890,625	n/a	4
5	Regulatory Asset - Income Tax Gross Up										273,494,709	271,052,792	268,610,875	266,168,958		5
6	Regulatory Asset Amortization - Income Tax Gross-Up		-	-	-	-	-	-	-	-	2,441,917	2,441,917	2,441,917	2,441,917	9,767,668	6
7	Unamortized Regulatory Asset - Income Tax Gross Up										$ 271,052,792	$ 268,610,875	$ 266,168,958	$ 263,727,041		7
8	Return on Unamortized Regulatory Asset - Loss of PPA only															
	a. Equity Component [a]		-	-	-	-	-	-	-	-	$ 866,849	$ 1,725,888	$ 1,710,269	$ 1,694,650	5,997,656	8a
	b. Equity Comp. grossed up for taxes (Line 8a / 0.61425) [b]		-	-	-	-	-	-	-	-	1,411,231	2,809,749	2,784,321	2,758,893	9,764,194	8b
	c. Debt Component (Line 4 * 1.4904% / 12)		-	-	-	-	-	-	-	-	268,031	533,647	528,818	523,988	1,854,483	8c
9	Total Return Requirements (Line 8b + 8c)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,679,262	$ 3,343,395	$ 3,313,139	$ 3,282,882	$ 11,618,678	9
10	Total Recoverable Expenses (Line 2 + 6 + 9)										$ 8,009,572	$ 9,673,705	$ 9,643,449	$ 9,613,192	$ 36,939,918	10

[a] The monthly Equity Component for the Jan. - Jun. 2015 actual period is 4.8938%, reflects a 10.5% return on equity. Monthly Equity Component for the Jul. - Dec. 2015 estimated period is 4.8201% based on the May 2015 ROR Earnings Surveillance Report, reflects a 10.5% return on equity, consistent with FPSC Order No. PSC-12-0425-PAA-EU.

[b] Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35%.
[c] The Debt Component for the Jan. - Jun. 2015 actual period is 1.4751%. Debt Component for the Jul. - Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Earnings Surveillance Report, reflects a 10.5% ROE, consistent with FPSC Order No. PSC-12-0425-PAA-EU.
[d] Recovery of the Cedar Bay Transaction is based on the settlement agreement approved by the FPSC in Docket No. 150075-EI at the special agenda on August 27th, 2015.

TOTAL MAY NOT ADD DUE TO ROUNDING

FLORIDA POWER & LIGHT COMPANY

CEDAR BAY TRANSACTION

Regulatory Liability - Book/Tax Timing Difference Associated to Plant Asset - Amortization and Return Calculation

For the Period January through December 2015

Line No.	Description	Beginning of Period	January	February	March	April	May	June	July	August	September	October	November	December	Total	Line. No.
1	Regulatory Liability - Book/Tax Timing Difference		-	-	-	-	-	-	-	-	$ (7,076,465)	$ (7,013,282)	$ (6,950,099)	$ (6,886,916)	n/a	1
2	Regulatory Liability Amortization		-	-	-	-	-	-	-	-	63,183	63,183	63,183	63,183	$ 252,732	2
3	Unamortized Regulatory Liability - Book/Tax Timing Diff	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,013,282)	$ (6,950,099)	$ (6,886,916)	$ (6,823,733)	n/a	3
4	Average Unamortized Regulatory Liability - Book/Tax Timing Difference		-	-	-	-	-	-	-	-	$ (3,506,641)	$ (6,981,691)	$ (6,918,508)	$ (6,855,325)	n/a	4
5	Return on Unamortized Regulatory Liability - Book/Tax Timing Difference															5
a.	Equity Component [(a)]		-	-	-	-	-	-	-	-	(14,085)	(28,044)	(27,790)	(27,536)	(97,456)	5a
b.	Equity Comp. grossed up for taxes (Line 5a / 0.61425) [(b)]		-	-	-	-	-	-	-	-	(22,931)	(45,656)	(45,243)	(44,829)	(158,659)	5b
c.	Debt Component (Line 4 * 1.4904% / 12)		-	-	-	-	-	-	-	-	(4,355)	(8,671)	(8,593)	(8,514)	(30,134)	5c
6	Total Return Requirements (Line 5b + 5c)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (27,286)	$ (54,327)	$ (53,835)	$ (53,344)	$ (188,793)	6
7	Total Recoverable Expenses (Line 2 + 6)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (90,469)	$ (117,510.03)	$ (117,018)	$ (116,527)	$ (441,525)	7

[(a)] The monthly Equity Component for the Jan. - Jun. 2015 actual period is 4.8938%, reflects a 10.5% return on equity. Monthly Equity Component for the Jul. - Dec. 2015 actual period is 4.8201% based on the May 2015 ROR Earnings Surveillance Report, reflects a 10.5% return on equity, consistent with FPSC Order No. PSC-12-0425-PAA-EU.
[(b)] Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35%.
[(c)] The Debt Component for the Jan. - Jun. 2015 actual period is 1.4751%. Debt Component for the Jul. - Dec. 2015 estimated period is 1.4904% based on the May 2015 ROR Earnings Surveillance Report, reflects a 10.5% ROE, consistent with FPSC Order No. PSC-12-0425-PAA-EU.
[(d)] Recovery of the Cedar Bay Transaction is based on the settlement agreement approved by the FPSC in Docket No. 150075-EI at the special agenda on August 27th, 2015.

TOTAL MAY NOT ADD DUE TO ROUNDING

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.50%

CAPITAL STRUCTURE AND COST RATES PER MAY 2014 EARNINGS SURVEILLANCE REPORT

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	7,260,190,891	29.609%	4.77%	1.41%	1.41%
SHORT_TERM_DEBT	303,811,216	1.239%	2.18%	0.03%	0.03%
PREFERRED_STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER_DEPOSITS	422,415,505	1.723%	2.04%	0.04%	0.04%
COMMON_EQUITY	11,427,411,916	46.604%	10.50%	4.89%	7.97%
DEFERRED_INCOME_TAX	5,104,824,995	20.819%	0.00%	0.00%	0.00%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	1,326,963	0.005%	8.27%	0.00%	0.00%
TOTAL	$24,519,981,486	100.00%		6.37%	9.44%

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	$7,260,190,891	38.85%	4.772%	1.854%	1.854%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	11,427,411,916	61.15%	10.500%	6.421%	10.453%
TOTAL	$18,687,602,807	100.00%		8.275%	12.307%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	1.4129%
SHORT TERM DEBT	0.0270%
CUSTOMER DEPOSITS	0.0352%
TAX CREDITS -WEIGHTED	0.0001%
TOTAL DEBT	**1.4751%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.8935%
TAX CREDITS -WEIGHTED	0.0003%
TOTAL EQUITY	**4.8938%**
TOTAL	6.3690%
PRE-TAX EQUITY	7.9671%
PRE-TAX TOTAL	9.4423%

Note:

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

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.50%

CAPITAL STRUCTURE AND COST RATES PER MAY 2015 EARNINGS SURVEILLANCE REPORT

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	7,868,539,536	29.834%	4.80%	1.43%	1.43%
SHORT_TERM_DEBT	346,840,443	1.315%	2.03%	0.03%	0.03%
PREFERRED_STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER_DEPOSITS	421,524,845	1.598%	2.04%	0.03%	0.03%
COMMON_EQUITY	12,106,290,409	45.901%	10.50%	4.82%	7.85%
DEFERRED_INCOME_TAX	5,629,438,935	21.344%	0.00%	0.00%	0.00%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	2,138,560	0.008%	8.25%	0.00%	0.00%
TOTAL	$26,374,772,728	100.00%		6.31%	9.34%

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	$7,868,539,536	39.39%	4.796%	1.889%	1.889%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	12,106,290,409	60.61%	10.500%	6.364%	10.360%
TOTAL	$19,974,829,945	100.00%		8.253%	12.250%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	1.4309%
SHORT TERM DEBT	0.0267%
CUSTOMER DEPOSITS	0.0326%
TAX CREDITS -WEIGHTED	0.0002%
TOTAL DEBT	**1.4904%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.8196%
TAX CREDITS -WEIGHTED	0.0005%
TOTAL EQUITY	**4.8201%**
TOTAL	6.3105%
PRE-TAX EQUITY	7.8472%
PRE-TAX TOTAL	9.3375%

Note:

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

APPENDIX I

FUEL COST RECOVERY

ACTUAL/ESTIMATED TRUE UP CALCULATION

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 20
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT & SUPPLEMENTAL)*Notice of Adoption of Terry J. Keith's testimony and exhibits by Renae B. Deaton, filed on October 3, 2016, (FPSC DN #07930-16).
DESCRIPTION: *R. B. Deaton TJK-3

TJK-3
DOCKET NO. 160001-EI
FPL WITNESS: TERRY J. KEITH
EXHIBIT _____
PAGES 1-40
AUGUST 4, 2016

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE

SCHEDULE: E1-B

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2016 THROUGH DECEMBER 2016

Line No.	(1)	(2) January Actual	(3) February Actual	(4) March Actual	(5) April Actual	(6) May Actual	(7) June Actual	(8) July Estimated	(9) August Estimated	(10) September Estimated	(11) October Estimated	(12) November Estimated	(13) December Estimated	(14) 12 Month Period
1	**Fuel Costs & Net Power Transactions**													
2	Fuel Cost of System Net Generation (Per A3) [1]	$201,632,120	$185,554,216	$191,236,901	$218,364,742	$229,257,708	$252,425,555	$279,411,788	$277,561,133	$254,146,222	$247,448,493	$202,033,361	$210,377,139	$2,749,449,379
3	Cedar Bay – Rail Coal Cars Lease per Docket No. 150075-EI	$137,532	$271,278	$147,241	$144,435	$130,857	$131,751	$120,000	$120,000	$120,000	$120,000	$120,000	$120,000	$1,683,092
4	Fuel Cost of Power Sold (Per A6)	($10,675,105)	($6,757,682)	($2,453,228)	($4,786,732)	($2,412,798)	($2,003,416)	($3,296,115)	($3,010,994)	($2,575,173)	($1,765,432)	($2,395,112)	($2,923,429)	($45,055,217)
5	Gains from Off-System Sales (Per A6)	($3,997,835)	($2,907,354)	($793,597)	($3,079,923)	($951,874)	($601,482)	($661,300)	($636,800)	($690,175)	($347,950)	($366,200)	($547,200)	($15,581,690)
6	Fuel Cost of Purchased Power (Per A7)	$2,411,393	$5,384,645	$6,690,344	$6,408,911	$6,721,506	$7,054,568	$9,695,065	$9,292,904	$8,393,801	$8,875,483	$8,086,463	$8,274,505	$87,289,589
7	Energy Payments to Qualifying Facilities (Per A8)	$386,643	$317,765	$1,801,911	$3,858,818	$4,895,544	$3,134,762	$5,695,041	$5,627,758	$5,076,456	$820,975	$776,682	$736,183	$33,128,538
8	Energy Cost of Economy Purchases (Per A9)	$145,200	$9,812	$664,006	$6,285,624	$6,470,979	$7,168,322	$11,047,465	$12,055,237	$8,404,287	$7,699,370	$716,733	$416,295	$61,083,332
9	Total Fuel Costs & Net Power Transactions	$190,039,948	$181,872,680	$197,293,578	$227,195,875	$244,111,921	$267,310,058	$302,011,944	$301,009,240	$272,875,418	$262,850,938	$208,971,929	$216,453,493	$2,871,997,022
10														
11	**Incremental Optimization Costs**													
12	Incremental Personnel, Software, and Hardware Costs (Per A2)	$39,910	$36,980	$41,605	$39,413	$40,308	$41,454	$38,227	$41,180	$39,704	$38,227	$39,704	$39,704	$476,415
13	Variable Power Plant O&M Costs over 514,000 MWH Threshold (Per A6)	$1,317	$589,232	$270,672	$518,520	$201,262	$119,589	$93,432	$88,672	$99,280	$89,760	$101,320	$146,880	$2,319,937
14	Total	$41,226	$626,213	$312,277	$557,934	$241,570	$161,043	$131,659	$129,852	$138,984	$127,987	$141,024	$186,584	$2,796,352
15														
16	Dodd Frank Fees	$375	$0	$750	$0	$750	$375	$375	$375	$375	$375	$375	$375	$4,500
17														
18	**Adjustments to Fuel Cost**													
19	Energy Imbalance Fuel Revenues	($548)	$7,315	$6,763	$20,705	$8,753	$14,117	$0	$0	$0	$0	$0	$0	$57,105
20	Inventory Adjustments	($677,969)	$91,469	($178,709)	$82,937	($157,064)	$120,075	$0	$0	$0	$0	$0	$0	($719,260)
21	Non Recoverable Oil/Tank Bottoms	$0	$0	($80,208)	$0	$0	$230,772	$0	$0	$0	$0	$0	$0	$150,564
22	Gas Reserves Refund [5]	$0	$0	$0	$0	$0	($21,294,315)	$0	$0	$0	$0	$0	$0	($21,294,315)
23	Variable Power Plant O&M Correction [6]	$0	$0	$0	$0	$0	($832,856)	$0	$0	$0	$0	$0	$0	($832,856)
24	Adjusted Total Fuel Costs & Net Power Transactions	$189,403,032	$182,597,676	$197,354,451	$227,857,451	$244,205,930	$245,709,269	$302,143,979	$301,139,467	$273,014,776	$262,979,300	$209,113,327	$216,640,452	$2,852,159,111
25	**Jurisdictional kWh Sales**													
26	Jurisdictional kWh Sales	8,477,060,498	7,108,751,712	7,791,736,459	8,414,360,754	8,721,865,851	10,084,259,719	10,360,306,400	10,493,894,259	10,260,705,262	9,462,770,364	8,246,522,500	8,151,744,737	107,573,978,515
27	Sales for Resale	504,756,935	509,624,758	435,645,390	536,378,082	517,499,753	594,973,322	629,857,352	648,939,796	625,840,767	594,452,738	540,505,365	443,461,630	6,581,935,888
28	Sub-Total Sales	8,981,817,433	7,618,376,470	8,227,381,849	8,950,738,836	9,239,365,604	10,679,233,041	10,990,163,752	11,142,834,055	10,886,546,029	10,057,223,102	8,787,027,865	8,595,206,367	114,155,914,403
29														
30	**Jurisdictional % of Total Sales (Line 26/28)**	94.38024%	93.31059%	94.70493%	94.00744%	94.39897%	94.42869%	94.26890%	94.17617%	94.25125%	94.08930%	93.84883%	94.84059%	94.23426%
31	**True-up Calculation**													
32	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$242,137,682	$200,663,968	$220,698,604	$206,705,034	$216,009,593	$253,879,070	$258,303,532	$261,634,149	$255,820,273	$235,926,131	$205,602,596	$203,239,593	$2,760,620,225
33	**Fuel Adjustment Revenues Not Applicable to Period**													
34	Prior Period True-up (Collected)/Refunded This Period [2]	($5,568,187)	($5,568,187)	($5,568,187)	($5,568,187)	($5,568,187)	($5,568,187)	($5,568,187)	($5,568,187)	($5,568,187)	($5,568,187)	($5,568,187)	($5,568,187)	($66,818,243)
35	GPIF, Net of Revenue Taxes [3]	($1,940,528)	($1,940,528)	($1,940,528)	($1,940,528)	($1,940,528)	($1,940,528)	($1,940,528)	($1,940,528)	($1,940,528)	($1,940,528)	($1,940,528)	($1,940,528)	($23,286,336)
36	Incentive Mechanism Collection	($1,028,392)	($1,028,392)	($1,028,392)	($1,028,392)	($1,028,392)	($1,028,392)	($1,028,392)	($1,028,392)	($1,028,392)	($1,028,392)	($1,028,392)	($1,028,392)	($12,340,708)
37	Midcourse correction - Prior Period True-up (Collected)/Refunded This Period	$0	$0	$0	$3,307,472	$3,307,472	$3,307,472	$3,307,472	$3,307,472	$3,307,472	$3,307,472	$3,307,472	$3,307,472	$29,767,250
38	Jurisdictional Fuel Revenues Applicable to Period	$233,600,575	$192,126,861	$212,161,496	$201,475,399	$210,779,958	$248,649,435	$253,073,897	$256,404,514	$250,590,638	$230,696,496	$200,372,961	$198,009,958	$2,687,942,188
39	Adjusted Total Fuel Costs & Net Power Transactions	$189,403,032	$182,597,676	$197,354,451	$227,857,451	$244,205,930	$245,709,269	$302,143,979	$301,139,467	$273,014,776	$262,979,300	$209,113,327	$216,640,452	$2,852,159,111
40	Jurisdictional Sales % of Total kWh Sales (Line 30)	94.38024%	93.31059%	94.70493%	94.00744%	94.39897%	94.42869%	94.26890%	94.17617%	94.25125%	94.08930%	93.84883%	94.84059%	94.23426%
41	Juris. Total Fuel Costs & Net Power Trans. (Line 39xLine40x1.00168)	$179,104,042	$170,711,808	$187,265,120	$214,562,817	$230,915,170	$232,409,838	$285,306,316	$284,078,067	$257,752,137	$247,851,074	$196,580,112	$205,808,261	$2,692,344,761
42	True-up Provision for the Month - Over/(Under) Recovery (Line 38 - Line 41)	$54,496,533	$21,415,052	$24,896,376	($13,087,418)	($20,135,212)	$16,239,597	($32,232,419)	($27,673,552)	($7,161,499)	($17,154,578)	$3,792,849	($7,798,303)	($4,402,573)
43	Interest Provision for the Month	($2,339)	$12,473	$23,375	$24,402	$17,722	$18,833	$18,730	$11,160	$6,363	$3,231	$1,832	$1,914	$137,694
44	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	($66,818,243)	($6,755,862)	$20,239,850	$50,727,789	$39,925,486	$22,068,711	$40,587,856	$10,634,881	($14,766,796)	($19,661,218)	($34,551,850)	($28,496,455)	($66,818,243)
45	Deferred True-up Beginning of Period - Over/(Under) Recovery [4]	$29,767,250	$29,767,250	$29,767,250	$29,767,250	$29,767,250	$29,767,250	$29,767,250	$29,767,250	$29,767,250	$29,767,250	$29,767,250	$29,767,250	$29,767,250
46	Prior Period True-up Collected/(Refunded) This Period [2]	$5,568,187	$5,568,187	$5,568,187	$5,568,187	$5,568,187	$5,568,187	$5,568,187	$5,568,187	$5,568,187	$5,568,187	$5,568,187	$5,568,187	$66,818,243
47	Vendor Settlement Refund per Order No. PSC-16-0298-FOF-EI [7]							$7,541,512	$7,541,512	$7,541,512	$7,541,512	$7,541,512	$7,541,512	$7,541,512
48	Midcourse correction - 2015 Final true-up collected/(refunded) this period	$0	$0	$0	($3,307,472)	($3,307,472)	($3,307,472)	($3,307,472)	($3,307,472)	($3,307,472)	($3,307,472)	($3,307,472)	($3,307,472)	($29,767,250)
49	End of Period Net True-up Amount Over/(Under) Recovery (Lines 42 through 47)	$23,011,388	$50,007,100	$80,495,039	$69,692,736	$51,835,961	$70,355,106	$47,943,643	$22,541,966	$17,647,544	$2,756,912	$8,812,307	$3,276,633	$3,276,633
50														
51														

[1] January through June actuals include various adjustments as noted on the A-Schedules.

[2] Prior Period 2015 Actual/Estimated True-up.

[3] Generation Performance Incentive Factor is (($23,303,114/12) x 99.9280%) - See Order No. PSC-15-0586-FOF-EI.

[4] 2015 Final True-up.

[5] As a result of the Florida Supreme Court's decision, FPL is including a Gas Reserves Refund of $24,532,560 calculated from March 2015 through June 2016. This $24,532,560 consists of $21,294,315 credited to customers in June 2016 plus $3,238,245 that is already reflected in the monthly true-up amounts.

[6] FPL has included a refund of $832,856 including resulting from the application of the corrected variable power plant O&M rate to wholesale economy energy sales for the period January 2013 through April 2016.

[7] Per Order No. PSC-16-0298-FOF-EI, issued on July 27, 2016, FPL is including a refund of $7,541,512 in the calculation of its 2016 end-of-period net true-up amount, which represents the jurisdictional amount associated with FPL's vendor settlement of $8 million.

Note: Totals may not add down due to rounding.

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF VARIANCE - ACTUAL/ESTIMATED vs. MID COURSE CORRECTION

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2016 THROUGH DECEMBER 2016

Line No.	(1)	(2) FCR - 2016 Actual Estimated	(3) FCR - 2016 Mid Course Correction	(4) Dif. FCR - 2016 Mid Course Correction	(5) % Dif. FCR - 2016 Mid Course Correction
1	**Fuel Costs & Net Power Transactions**				
2	Fuel Cost of System Net Generation (Per A3) [1]	$2,749,449,379	$2,765,439,139	($15,989,761)	(0.6%)
3	Cedar Bay – Rail Coal Cars Lease per Docket No. 150075-EI	$1,683,092	$1,357,080	$326,012	24.0%
4	Fuel Cost of Power Sold (Per A6)	($45,055,217)	($46,084,559)	$1,029,343	(2.2%)
5	Gains from Off-System Sales (Per A6)	($15,581,690)	($13,419,650)	($2,162,040)	16.1%
6	Fuel Cost of Purchased Power (Per A7)	$87,289,589	$88,397,181	($1,107,593)	(1.3%)
7	Energy Payments to Qualifying Facilities (Per A8)	$33,128,538	$34,218,981	($1,090,443)	(3.2%)
8	Energy Cost of Economy Purchases (Per A9)	$61,083,332	$28,049,545	$33,033,786	117.8%
9	Total Fuel Costs & Net Power Transactions	$2,871,997,022	$2,857,957,717	$14,039,305	0.5%
10					
11	**Incremental Optimization Costs**				
12	Incremental Personnel, Software, and Hardware Costs (Per A2)	$476,415	$473,512	$2,903	0.61%
13	Variable Power Plant O&M Costs over 514,000 MWH Threshold (Per A6)	$2,319,937	$1,498,826	$821,111	54.78%
14	Total	$2,796,352	$1,972,338	$824,014	41.78%
15					
16	Dodd Frank Fees	$4,500	$4,500	$0	0.0%
17					
18	**Adjustments to Fuel Cost**				
19	Energy Imbalance Fuel Revenues	$57,105	$0	$57,105	N/A
20	Inventory Adjustments	($719,260)	$0	($719,260)	N/A
21	Non Recoverable Oil/Tank Bottoms	$150,564	$0	$150,564	N/A
22	Gas Reserves Refund [5]	($21,294,315)	$0	($21,294,315)	0.0%
23	Variable Power Plant O&M Correction [6]	($832,856)	$0	($832,856)	0.0%
24	Adjusted Total Fuel Costs & Net Power Transactions	$2,852,159,111	$2,859,934,555	($7,775,444)	(0.3%)
25	**Jurisdictional kWh Sales**				
26	Jurisdictional kWh Sales	107,573,978,515	107,374,013,439	199,965,076	0.2%
27	Sales for Resale	6,581,935,888	6,524,197,203	57,738,685	0.9%
28	Sub-Total Sales	114,155,914,403	113,898,210,642	257,703,761	0.2%
29					
30	**Jurisdictional % of Total Sales (Line 26/28)**	N/A	N/A	N/A	N/A
31	**True-up Calculation**				
32	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$2,760,620,225	$2,773,438,835	($12,818,610)	(0.5%)
33	**Fuel Adjustment Revenues Not Applicable to Period**				
34	Prior Period True-up (Collected)/Refunded This Period [2]	($66,818,243)	($66,818,243)	$0	0.0%
35	GPIF, Net of Revenue Taxes [3]	($23,286,336)	($23,286,336)	$0	(0.0%)
36	Incentive Mechanism Collection	($12,340,708)	($12,340,708)	$0	(0.0%)
37	Midcourse correction - Prior Period True-up (Collected)/Refunded This Period	$29,767,250	$29,767,250	$0	0.0%
38	Jurisdictional Fuel Revenues Applicable to Period	$2,687,942,188	$2,700,760,798	($12,818,610)	(0.5%)
39	Adjusted Total Fuel Costs & Net Power Transactions	$2,852,159,111	$2,859,934,555	($7,775,444)	(0.3%)
40	Jurisdictional Sales % of Total kWh Sales (Line 30)	N/A	N/A	N/A	N/A
41	Juris. Total Fuel Costs & Net Power Trans. (Line 39xLine40x1.00168)	$2,692,344,761	$2,700,760,798	($8,416,037)	(0.3%)
42	True-up Provision for the Month - Over/(Under) Recovery (Line 38 - Line 41)	($4,402,573)	$0	($4,402,573)	N/A
43	Interest Provision for the Month	$137,694	$0	$137,694	N/A
44	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	($66,818,243)	($66,818,243)	$0	0.0%
45	Deferred True-up Beginning of Period - Over/(Under) Recovery [4]	$29,767,250	$29,767,250	$0	N/A
46	Prior Period True-up Collected/(Refunded) This Period [2]	$66,818,243	$66,818,243	$0	0.0%
47	Vendor Settlement Refund per Order No. PSC-16-0298-FOF-EI [7]	$7,541,512	$0	$7,541,512	0.0%
48	Midcourse correction - 2015 Final true-up collected/(refunded) this period	($29,767,250)	($29,767,250)	$0	0.0%
49	End of Period Net True-up Amount Over/(Under) Recovery (Lines 42 through 47	$3,276,633	$0	$3,276,633	0.0%
50					

51 [1] January through June actuals include various adjustments as noted on the A-Schedules.

52 [2] Prior Period 2015 Actual/Estimated True-up.

53 [3] Generation Performance Incentive Factor is (($23,303,114/12) x 99.9280%) - See Order No. PSC-15-0586-FOF-EI.

54 [4] 2015 Final True-up.

55 [5] As a result of the Florida Supreme Court's decision, FPL is including a Gas Reserves Refund of $24,532,560 calculated from March 2015 through June 2016.

56 This $24,532,560 consists of $21,294,315 credited to customers in June 2016 plus $3,238,245 that is already reflected in the monthly true-up amounts.

57 [6] FPL has included a refund of $832,856 including resulting from the application of the corrected variable power plant O&M rate to wholesale economy energy sales for the period January 2013 through April 2016.

58 [7] Per Order No. PSC-16-0298-FOF-EI, issued on July 27, 2016, FPL is including a refund of $7,541,512 in the calculation of its 2016 end-of-period net true-up amount, which represents the jurisdictional amount associated with FPL's vendor settlement of $8 million.

59 Note: Totals may not add down due to rounding.

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

SCHEDULE: E3

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2016 THROUGH DECEMBER 2016

Line No.		January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	12 Month Period
1	**Fuel Cost of System Net Generation ($)**													
2	Heavy Oil	2,266,057	302,086	705,120	730,041	235,779	7,522,261	9,012,839	9,460,877	2,843,615	2,302,004	418,773	0	35,799,452
3	Light Oil	335,843	2,545,794	3,860,828	2,544,739	1,281,610	1,537,919	2,002,109	2,284,599	2,441,081	1,390,005	2,179,492	2,860,252	25,264,270
4	Coal	8,227,200	8,005,916	6,899,567	2,574,122	7,929,380	8,841,867	14,607,692	13,252,968	10,990,093	12,802,731	11,006,577	10,757,260	115,895,372
5	Gas	172,614,616	157,548,569	162,633,373	198,586,796	201,801,097	216,949,414	235,624,455	234,397,997	221,103,110	217,813,622	170,829,493	178,241,815	2,368,144,358
6	Nuclear	18,188,995	17,151,950	17,373,119	13,692,467	18,009,842	17,574,094	18,164,692	18,164,692	16,768,323	13,140,131	17,599,027	18,517,813	204,345,144
7	**Total Fuel Cost of System Net Generation ($)**	201,632,711	185,554,314	191,472,006	218,128,165	229,257,709	252,425,554	279,411,788	277,561,133	254,146,222	247,448,493	202,033,361	210,377,139	2,749,448,596
8														
9	**System Net Generation (MWh)**													
10	Heavy Oil	9,982	1,478	3,034	3,129	1,044	44,404	48,808	53,531	15,096	12,765	2,396	0	195,667
11	Light Oil	14,837	7,915	32,353	4,934	8,806	10,520	12,005	13,502	20,723	8,501	19,849	26,316	180,261
12	Coal	280,284	277,939	231,631	78,830	221,326	449,552	481,841	432,545	375,960	424,150	387,336	374,066	4,015,461
13	Gas	5,984,630	5,385,395	6,383,470	7,249,566	7,548,261	8,134,483	8,139,848	8,310,000	7,777,840	7,613,325	5,511,443	5,636,496	83,674,756
14	Nuclear	2,636,120	2,480,541	2,563,685	1,942,308	2,588,195	2,506,725	2,504,806	2,504,806	2,309,222	1,793,142	2,445,128	2,575,172	28,849,851
15	Solar [c]	3,872	5,027	5,826	6,371	7,349	5,924	19,468	18,290	40,584	39,153	32,250	28,675	212,789
16	**Total System Net Generation (MWh)**	8,929,725	8,158,295	9,219,999	9,285,138	10,374,981	11,151,608	11,206,776	11,332,674	10,539,425	9,891,036	8,398,402	8,640,725	117,128,783
17														
18	**Units of Fuel Burned (Unit)** [a]													
19	Heavy Oil	24,740	3,319	7,709	7,932	2,573	81,740	97,728	107,684	32,222	26,296	4,929	0	396,871
20	Light Oil	2,916	26,186	34,884	25,446	10,689	14,081	16,083	18,567	24,440	12,256	22,626	30,150	238,323
21	Coal [b]	172,548	171,153	136,477	23,422	156,356	167,676	291,719	264,375	231,617	259,905	236,242	229,518	2,341,007
22	Gas	43,002,781	38,393,775	44,148,911	52,659,707	54,190,551	58,124,683	58,192,298	59,482,630	55,584,192	53,864,448	39,243,220	39,344,879	596,232,077
23	Nuclear	28,591,481	26,881,873	27,997,870	21,474,486	28,523,693	27,807,377	27,645,237	27,645,237	25,506,668	19,915,143	26,997,177	28,424,310	317,410,552
24														
25														
26	**BTU Burned (MMBTU)**													
27	Heavy Oil	156,143	20,962	48,517	49,998	16,240	516,767	625,462	689,175	206,220	168,292	31,546	0	2,529,323
28	Light Oil	16,753	27,983	156,253	43,152	62,522	81,875	93,766	108,243	142,483	71,454	131,907	175,774	1,112,165
29	Coal	3,234,570	2,977,967	2,533,711	717,732	2,846,217	3,068,536	5,341,915	4,860,759	4,193,456	4,771,059	4,263,604	4,155,370	42,964,895
30	Gas	43,078,160	39,323,023	45,172,523	53,815,304	55,301,053	59,212,680	58,192,298	59,482,630	55,584,192	53,864,448	39,243,220	39,344,879	601,614,410
31	Nuclear	28,591,481	26,881,873	27,997,870	21,474,486	28,523,693	27,807,377	27,645,237	27,645,237	25,506,668	19,915,143	26,997,177	28,424,310	317,410,552
32	**Total BTU Burned (MMBTU)**	75,077,108	69,231,808	75,908,875	76,100,671	86,749,725	90,687,235	91,898,678	92,786,044	85,633,019	78,790,396	70,667,454	72,100,333	965,631,345
33														
34	**Fuel Cost per Unit ($/Unit)**													
35	Heavy Oil	91.5945	91.0089	91.4694	92.0421	91.6288	92.0270	92.2233	87.8581	88.2511	87.5432	84.9600	0.0000	90.2042
36	Light Oil	115.1723	97.2197	110.6762	100.0055	119.8999	109.2194	124.4833	123.0492	99.8821	113.4118	96.3288	94.8677	106.0084
37	Coal	47.6807	46.7763	50.5550	109.9020	50.7137	52.7319	50.0746	50.1295	47.4493	49.2593	46.5904	46.8689	49.5066
38	Gas	4.0140	4.1035	3.6837	3.7711	3.7239	3.7325	4.0491	3.9406	3.9778	4.0437	4.3531	4.5302	3.9718
39	Nuclear	0.6362	0.6380	0.6205	0.6376	0.6314	0.6320	0.6571	0.6571	0.6574	0.6598	0.6519	0.6515	0.6438
40														
41														

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

SCHEDULE: E3

FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2016 THROUGH DECEMBER 2016

Line No.		January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	12 Month Period
1	**Generation Mix (%)**													
2	Heavy Oil	0.11%	0.02%	0.03%	0.03%	0.01%	0.40%	0.44%	0.47%	0.14%	0.13%	0.03%	0.00%	0.17%
3	Light Oil	0.17%	0.10%	0.35%	0.05%	0.08%	0.09%	0.11%	0.12%	0.20%	0.09%	0.24%	0.30%	0.15%
4	Coal	3.14%	3.41%	2.51%	0.85%	2.13%	4.03%	4.30%	3.82%	3.57%	4.29%	4.61%	4.33%	3.43%
5	Gas	67.02%	66.01%	69.24%	78.08%	72.75%	72.94%	72.63%	73.33%	73.80%	76.97%	65.62%	65.23%	71.44%
6	Nuclear	29.52%	30.41%	27.81%	20.92%	24.95%	22.48%	22.35%	22.10%	21.91%	18.13%	29.11%	29.80%	24.63%
7	Solar [c]	0.04%	0.06%	0.06%	0.07%	0.07%	0.05%	0.17%	0.16%	0.39%	0.40%	0.38%	0.33%	0.18%
8	**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%
9														
10	**Fuel Cost per MMBTU ($/MMBTU)**													
11	Heavy Oil	14.5127	14.4113	14.5334	14.6015	14.5186	14.5564	14.4099	13.7278	13.7892	13.6786	13.2750	0.0000	14.1538
12	Light Oil	20.0468	90.9755	24.7088	58.9721	20.4984	18.7837	21.3522	21.1062	17.1324	19.4531	16.5229	16.2723	22.7163
13	Coal	2.5435	2.6884	2.7231	3.5865	2.7859	2.8815	2.7345	2.7265	2.6208	2.6834	2.5815	2.5888	2.6974
14	Gas	4.0070	4.0065	3.6003	3.6902	3.6491	3.6639	4.0491	3.9406	3.9778	4.0437	4.3531	4.5302	3.9363
15	Nuclear	0.6362	0.6380	0.6205	0.6376	0.6314	0.6320	0.6571	0.6571	0.6574	0.6598	0.6519	0.6515	0.6438
16														
17	**BTU Burned per KWH (BTU/KWH)**													
18	Heavy Oil	15,642	14,179	15,991	15,977	15,554	11,638	12,815	12,874	13,661	13,184	13,168	0	12,927
19	Light Oil	1,129	3,536	4,830	8,746	7,100	7,783	7,811	8,017	6,876	8,405	6,646	6,679	6,170
20	Coal	11,540	10,714	10,939	9,105	12,860	6,826	11,086	11,238	11,154	11,249	11,007	11,109	10,700
21	Gas	7,198	7,302	7,076	7,423	7,326	7,279	7,149	7,158	7,146	7,075	7,120	6,980	7,190
22	Nuclear	10,846	10,837	10,921	11,056	11,021	11,093	11,037	11,037	11,046	11,106	11,041	11,038	11,002
23														
24	**Generated Fuel Cost per KWH (cents/KWH)**													
25	Heavy Oil	22.7009	20.4344	23.2398	23.3291	22.5829	16.9405	18.4658	17.6738	18.8373	18.0338	17.4807	0.0000	18.2961
26	Light Oil	2.2635	32.1657	11.9334	51.5788	14.5541	14.6188	16.6779	16.9200	11.7796	16.3510	10.9804	10.8687	14.0154
27	Coal	2.9353	2.8805	2.9787	3.2654	3.5827	1.9668	3.0316	3.0640	2.9232	3.0184	2.8416	2.8758	2.8862
28	Gas	2.8843	2.9255	2.5477	2.7393	2.6735	2.6670	2.8947	2.8207	2.8427	2.8610	3.0995	3.1623	2.8302
29	Nuclear	0.6900	0.6915	0.6777	0.7050	0.6958	0.7011	0.7252	0.7252	0.7261	0.7328	0.7198	0.7191	0.7083
30	**Total Generated Fuel Cost per KWH (cents/KWH)**	2.2580	2.2744	2.0767	2.3492	2.2097	2.2636	2.4932	2.4492	2.4114	2.5017	2.4056	2.4347	2.3474
31														
32														

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

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

35 [c] Actuals do not include Martin 8 solar

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ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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 - 2016**												
2	*Babcock PV Solar*												
3	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	0	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
5	*Cedar Bay FPL*												
6	Light Oil		1,119					2,928	5,830,000	17,069	429,155	38.35	146.58
7	Coal		15,626					9,533	25,000,000	238,315	986,433	6.31	103.48
8	Plant Unit Info	250	16,745	9.0%	9.0%	67.0%	15,251			255,384	1,415,589	8.45	
9	*CCEC 3*												
10	Light Oil		278					314	5,830,000	1,833	29,564	10.65	94.03
11	Gas		774,950					5,115,506	1,000,000	5,115,506	20,883,012	2.69	4.08
12	Plant Unit Info	1,223	775,228	85.2%	94.9%	85.2%	6,601			5,117,339	20,912,577	2.70	
13	*Citrus PV Solar*												
14	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	0	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
16	*Desoto Solar*												
17	Solar		4,991					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	25	4,991	26.8%	N/A	49.5%	N/A			N/A	N/A	N/A	
19	*Everglades 1-12*												
20	Light Oil		187					552	5,830,000	3,218	54,667	29.24	99.04
21	Gas		868					14,942	1,000,000	14,942	60,998	7.03	4.08
22	Plant Unit Info	346	1,055	0.4%	95.4%	21.8%	17,213			18,160	115,665	10.96	
23	*Fort Myers 1-12*												
24	Light Oil		161					373	5,830,000	2,176	41,988	26.08	112.50
25	Plant Unit Info	541	161	0.0%	87.1%	29.8%	13,516			2,176	41,988	26.08	
26	*Fort Myers 2*												
27	Gas		692,510					5,146,907	1,000,000	5,146,907	21,011,209	3.03	4.08
28	Plant Unit Info	1,470	692,510	63.3%	95.1%	63.3%	7,432			5,146,907	21,011,209	3.03	
29	*Fort Myers 3A*												
30	Light Oil		0					0	0	0	0	0.00	0.00
31	Gas		1,710					19,684	1,000,000	19,684	80,355	4.70	4.08
32	Plant Unit Info	146	1,710	1.6%	58.3%	97.3%	11,511			19,684	80,355	4.70	
33	*Fort Myers 3B*												
34	Light 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	0	0	0.0%	58.3%	0.0%	0			0	0	0.00	
37	*Fort Myers 4A*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Light Oil		0					0	0	0	0	0.00	0.00
2	Gas		0					0	0	0	0	0.00	0.00
3	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
4	*Fort Myers 4B*												
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	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
8	*Lauderdale 1-24*												
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	0	0	0.0%	95.4%	0.0%	0			0	0	0.00	
12	*Lauderdale 4*												
13	Light Oil		316					423	5,830,000	2,466	42,495	13.45	100.46
14	Gas		228,560					1,783,394	1,000,000	1,783,394	7,280,345	3.19	4.08
15	Plant Unit Info	431	228,876	71.4%	94.6%	71.4%	7,803			1,785,860	7,322,840	3.20	
16	*Lauderdale 5*												
17	Light Oil		290					388	5,830,000	2,264	39,014	13.45	100.46
18	Gas		230,960					1,802,708	1,000,000	1,802,708	7,359,190	3.19	4.08
19	Plant Unit Info	431	231,250	72.1%	94.7%	72.1%	7,805			1,804,972	7,398,204	3.20	
20	*Lauderdale 6 CT 1*												
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	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
24	*Lauderdale 6 CT 2*												
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	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
28	*Lauderdale 6 CT 3*												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
32	*Lauderdale 6 CT 4*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		0					0	0	0	0	0.00	0.00
35	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
36	*Lauderdale 6 CT 5*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
3	*Manatee 1*												
4	Heavy Oil		15,737					31,553	6,400,000	201,937	2,904,360	18.46	92.05
5	Gas		45,487					583,705	1,000,000	583,705	2,329,158	5.12	3.99
6	Plant Unit Info	781	61,224	10.5%	95.2%	51.6%	12,832			785,642	5,233,518	8.55	
7	*Manatee 2*												
8	Heavy Oil		12,240					24,797	6,400,000	158,698	2,282,475	18.65	92.05
9	Gas		32,502					421,405	1,000,000	421,405	1,681,530	5.17	3.99
10	Plant Unit Info	781	44,742	7.7%	95.1%	49.8%	12,966			580,103	3,964,005	8.86	
11	*Manatee 3*												
12	Gas		566,096					3,954,156	1,000,000	3,954,156	15,863,000	2.80	4.01
13	Plant Unit Info	1,087	566,096	70.0%	95.1%	70.0%	6,985			3,954,156	15,863,000	2.80	
14	*Manatee PV Solar*												
15	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	0	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
17	*Martin 1*												
18	Heavy Oil		7,070					14,578	6,400,000	93,298	1,334,192	18.87	91.52
19	Gas		22,036					290,801	1,000,000	290,801	1,187,137	5.39	4.08
20	Plant Unit Info	797	29,106	4.9%	95.2%	50.0%	13,197			384,099	2,521,329	8.66	
21	*Martin 2*												
22	Heavy Oil		2,572					5,275	6,400,000	33,760	482,779	18.77	91.52
23	Gas		8,387					110,075	1,000,000	110,075	449,358	5.36	4.08
24	Plant Unit Info	767	10,959	1.9%	95.3%	59.5%	13,125			143,835	932,137	8.51	
25	*Martin 3*												
26	Gas		0					0	0	0	0	0.00	0.00
27	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
28	*Martin 4*												
29	Gas		189,692					1,477,534	1,000,000	1,477,534	5,965,027	3.14	4.04
30	Plant Unit Info	447	189,692	57.0%	95.1%	57.0%	7,789			1,477,534	5,965,027	3.14	
31	*Martin 8*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		489,603					3,452,681	1,000,000	3,452,681	13,863,077	2.83	4.02
34	Plant Unit Info	1,007	489,603	65.4%	94.8%	65.4%	7,052			3,452,681	13,863,077	2.83	
35	*Martin 8 Solar*												
36	Solar		12,679					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	75	12,679	22.7%	N/A	36.4%	N/A			N/A	N/A	N/A	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	*PEEC*												
2	Light Oil		213					238	5,830,000	1,389	17,950	8.42	75.34
3	Gas		792,791					5,166,779	1,000,000	5,166,779	21,092,327	2.66	4.08
4	Plant Unit Info	1,234	793,004	86.4%	94.5%	86.4%	6,517			5,168,168	21,110,278	2.66	
5	*Riviera 5*												
6	Light Oil		8,044					9,190	5,830,000	53,575	1,168,180	14.52	127.12
7	Gas		681,593					4,539,848	1,000,000	4,539,848	18,533,013	2.72	4.08
8	Plant Unit Info	1,241	689,637	74.7%	94.9%	74.7%	6,661			4,593,423	19,701,193	2.86	
9	*Sanford 4*												
10	Gas		420,561					3,153,170	1,000,000	3,153,170	12,872,177	3.06	4.08
11	Plant Unit Info	955	420,561	59.2%	94.9%	59.2%	7,498			3,153,170	12,872,177	3.06	
12	*Sanford 5*												
13	Gas		443,716					3,310,723	1,000,000	3,310,723	13,515,357	3.05	4.08
14	Plant Unit Info	955	443,716	62.5%	94.9%	62.5%	7,461			3,310,723	13,515,357	3.05	
15	*Scherer 4*												
16	Coal		346,809					220,900	17,000,000	3,755,292	9,199,379	2.65	41.65
17	Plant Unit Info	598	346,809	77.9%	93.9%	77.9%	10,828			3,755,292	9,199,379	2.65	
18	*St Johns 1*												
19	Coal		60,488					31,063	22,000,000	683,396	2,241,252	3.71	72.15
20	Plant Unit Info	122	60,488	66.5%	94.0%	66.5%	11,298			683,396	2,241,252	3.71	
21	*St Johns 2*												
22	Coal		58,919					30,223	22,000,000	664,911	2,180,628	3.70	72.15
23	Plant Unit Info	122	58,919	64.8%	93.9%	64.8%	11,285			664,911	2,180,628	3.70	
24	*St Lucie 1*												
25	Nuclear		711,664					7,730,094	1,000,000	7,730,094	5,024,561	0.71	0.65
26	Plant Unit Info	981	711,664	97.5%	97.5%	97.5%	10,862			7,730,094	5,024,561	0.71	
27	*St Lucie 2*												
28	Nuclear		609,290					6,618,108	1,000,000	6,618,108	4,500,316	0.74	0.68
29	Plant Unit Info	840	609,290	97.5%	97.5%	97.5%	10,862			6,618,108	4,500,316	0.74	
30	*Space Coast*												
31	Solar		1,798					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	10	1,798	24.2%	N/A	44.6%	N/A			N/A	N/A	N/A	
33	*Turkey Point 1*												
34	Heavy Oil		11,189					21,526	6,400,000	137,769	2,009,032	17.95	93.33
35	Gas		25,046					308,370	1,000,000	308,370	1,258,858	5.03	4.08
36	Plant Unit Info	366	36,235	13.3%	95.4%	56.5%	12,312			446,139	3,267,890	9.02	
37	*Turkey Point 3*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

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)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	Nuclear		588,299					6,607,778	1,000,000	6,607,778	4,559,370	0.78	0.69
2	Plant Unit Info	811	588,299	97.5%	97.5%	97.5%	11,232			6,607,778	4,559,370	0.78	
3	*Turkey Point 4*												
4	Nuclear		595,553					6,689,257	1,000,000	6,689,257	4,080,445	0.69	0.61
5	Plant Unit Info	821	595,553	97.5%	97.5%	97.5%	11,232			6,689,257	4,080,445	0.69	
6	*Turkey Point 5*												
7	Light Oil		1,397					1,677	5,830,000	9,776	179,095	12.82	106.81
8	Gas		543,459					3,803,072	1,000,000	3,803,072	15,525,269	2.86	4.08
9	Plant Unit Info	1,087	544,856	67.4%	95.1%	67.4%	6,998			3,812,848	15,704,364	2.88	
10	*WCEC 01*												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		656,730					4,620,588	1,000,000	4,620,588	18,437,516	2.81	3.99
13	Plant Unit Info	1,182	656,730	74.7%	95.0%	74.7%	7,036			4,620,588	18,437,516	2.81	
14	*WCEC 02*												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		700,892					4,894,043	1,000,000	4,894,043	19,528,682	2.79	3.99
17	Plant Unit Info	1,172	700,892	80.4%	95.0%	80.4%	6,983			4,894,043	19,528,682	2.79	
18	*WCEC 03*												
19	Light Oil		0					0	0	0	0	0.00	0.00
20	Gas		591,699					4,222,207	1,000,000	4,222,207	16,847,862	2.85	3.99
21	Plant Unit Info	1,182	591,699	67.3%	95.0%	67.3%	7,136			4,222,207	16,847,862	2.85	
22	**System Totals**												
23	Plant Unit Info	24,285	11,206,776				8,200			91,898,678	279,411,788	2.49	
24													
25													
26													
27													
28													
29													
30													
31													
32													
33													
34													
35													
36													
37													

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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 - 2016**												
2	*Babcock PV Solar*												
3	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	0	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
5	*Cedar Bay FPL*												
6	Light Oil		1,119					2,928	5,830,000	17,069	429,155	38.34	146.58
7	Coal		15,661					9,553	25,000,000	238,813	988,495	6.31	103.48
8	Plant Unit Info	250	16,780	9.0%	9.0%	69.2%	15,249			255,882	1,417,650	8.45	
9	*CCEC 3*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		787,743					5,190,060	1,000,000	5,190,060	20,634,881	2.62	3.98
12	Plant Unit Info	1,223	787,743	86.6%	94.9%	86.6%	6,589			5,190,060	20,634,881	2.62	
13	*Citrus PV Solar*												
14	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	0	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
16	*Desoto Solar*												
17	Solar		4,743					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	25	4,743	25.5%	N/A	47.1%	N/A			N/A	N/A	N/A	
19	*Everglades 1-12*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		208					3,731	1,000,000	3,731	14,824	7.13	3.97
22	Plant Unit Info	349	208	0.1%	95.4%	11.9%	17,937			3,731	14,824	7.13	
23	*Fort Myers 1-12*												
24	Light Oil		927					2,167	5,830,000	12,635	243,804	26.30	112.50
25	Plant Unit Info	542	927	0.2%	87.1%	24.4%	13,630			12,635	243,804	26.30	
26	*Fort Myers 2*												
27	Gas		681,439					5,069,785	1,000,000	5,069,785	20,155,837	2.96	3.98
28	Plant Unit Info	1,470	681,439	62.3%	95.1%	62.3%	7,440			5,069,785	20,155,837	2.96	
29	*Fort Myers 3A*												
30	Light Oil		0					0	0	0	0	0.00	0.00
31	Gas		2,764					32,161	1,000,000	32,161	127,797	4.62	3.97
32	Plant Unit Info	146	2,764	2.5%	95.4%	94.5%	11,636			32,161	127,797	4.62	
33	*Fort Myers 3B*												
34	Light Oil		0					0	0	0	0	0.00	0.00
35	Gas		3,833					44,752	1,000,000	44,752	177,828	4.64	3.97
36	Plant Unit Info	145	3,833	3.6%	95.4%	94.3%	11,675			44,752	177,828	4.64	
37	*Fort Myers 4A*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Light Oil		0					0	0	0	0	0.00	0.00
2	Gas		0					0	0	0	0	0.00	0.00
3	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
4	*Fort Myers 4B*												
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	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
8	*Lauderdale 1-24*												
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	0	0	0.0%	95.4%	0.0%	0			0	0	0.00	
12	*Lauderdale 4*												
13	Light Oil		808					1,079	5,830,000	6,290	107,118	13.25	99.28
14	Gas		251,038					1,953,563	1,000,000	1,953,563	7,767,145	3.09	3.98
15	Plant Unit Info	431	251,846	78.5%	94.6%	78.5%	7,782			1,959,853	7,874,262	3.13	
16	*Lauderdale 5*												
17	Light Oil		414					553	5,830,000	3,224	54,904	13.25	99.28
18	Gas		256,140					1,992,733	1,000,000	1,992,733	7,922,803	3.09	3.98
19	Plant Unit Info	431	256,554	80.0%	94.7%	80.0%	7,780			1,995,957	7,977,707	3.11	
20	*Lauderdale 6 CT 1*												
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	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
24	*Lauderdale 6 CT 2*												
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	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
28	*Lauderdale 6 CT 3*												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
32	*Lauderdale 6 CT 4*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		0					0	0	0	0	0.00	0.00
35	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
36	*Lauderdale 6 CT 5*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
3	*Manatee 1*												
4	Heavy Oil		11,375					23,068	6,400,000	147,635	1,959,856	17.23	84.96
5	Gas		19,147					248,510	1,000,000	248,510	965,504	5.04	3.89
6	Plant Unit Info	781	30,521	5.3%	95.2%	53.5%	12,979			396,145	2,925,360	9.58	
7	*Manatee 2*												
8	Heavy Oil		9,832					20,243	6,400,000	129,556	1,719,857	17.49	84.96
9	Gas		24,237					319,384	1,000,000	319,384	1,240,147	5.12	3.88
10	Plant Unit Info	781	34,069	5.9%	95.1%	47.9%	13,177			448,940	2,960,004	8.69	
11	*Manatee 3*												
12	Gas		549,407					3,841,655	1,000,000	3,841,655	14,993,583	2.73	3.90
13	Plant Unit Info	1,087	549,407	67.9%	95.1%	67.9%	6,992			3,841,655	14,993,583	2.73	
14	*Manatee PV Solar*												
15	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	0	0	0.0%	N/A	0.0%	N/A			N/A	N/A	N/A	
17	*Martin 1*												
18	Heavy Oil		9,545					19,346	6,400,000	123,813	1,682,855	17.63	86.99
19	Gas		17,504					227,046	1,000,000	227,046	902,196	5.15	3.97
20	Plant Unit Info	796	27,049	4.6%	95.2%	51.5%	12,971			350,859	2,585,051	9.56	
21	*Martin 2*												
22	Heavy Oil		7,765					16,399	6,400,000	104,952	1,426,498	18.37	86.99
23	Gas		28,208					381,271	1,000,000	381,271	1,515,033	5.37	3.97
24	Plant Unit Info	767	35,973	6.3%	95.3%	50.9%	13,516			486,223	2,941,530	8.18	
25	*Martin 3*												
26	Gas		192,301					1,500,654	1,000,000	1,500,654	5,905,247	3.07	3.94
27	Plant Unit Info	453	192,301	57.1%	91.8%	59.0%	7,804			1,500,654	5,905,247	3.07	
28	*Martin 4*												
29	Gas		194,069					1,513,668	1,000,000	1,513,668	5,938,978	3.06	3.92
30	Plant Unit Info	447	194,069	58.4%	95.1%	58.4%	7,800			1,513,668	5,938,978	3.06	
31	*Martin 8*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		484,660					3,416,524	1,000,000	3,416,524	13,322,537	2.75	3.90
34	Plant Unit Info	1,007	484,660	64.7%	94.8%	64.7%	7,049			3,416,524	13,322,537	2.75	
35	*Martin 8 Solar*												
36	Solar		11,873					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	75	11,873	21.3%	N/A	39.3%	N/A			N/A	N/A	N/A	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	*PEEC*												
2	Light Oil		0					0	0	0	0	0.00	0.00
3	Gas		748,477					4,897,017	1,000,000	4,897,017	19,468,661	2.60	3.98
4	Plant Unit Info	1,234	748,477	81.5%	94.5%	81.5%	6,543			4,897,017	19,468,661	2.60	
5	*Riviera 5*												
6	Light Oil		7,835					8,959	5,830,000	52,231	1,138,875	14.54	127.12
7	Gas		676,516					4,509,760	1,000,000	4,509,760	17,928,526	2.65	3.98
8	Plant Unit Info	1,241	684,351	74.1%	94.9%	74.1%	6,666			4,561,991	19,067,401	2.79	
9	*Sanford 4*												
10	Gas		425,568					3,194,152	1,000,000	3,194,152	12,699,069	2.98	3.98
11	Plant Unit Info	955	425,568	59.9%	94.9%	59.9%	7,506			3,194,152	12,699,069	2.98	
12	*Sanford 5*												
13	Gas		414,349					3,091,899	1,000,000	3,091,899	12,293,091	2.97	3.98
14	Plant Unit Info	955	414,349	58.3%	82.8%	58.3%	7,462			3,091,899	12,293,091	2.97	
15	*Scherer 4*												
16	Coal		303,766					196,829	17,000,000	3,346,089	8,110,700	2.67	41.21
17	Plant Unit Info	598	303,766	68.3%	93.9%	68.3%	11,015			3,346,089	8,110,700	2.67	
18	*St Johns 1*												
19	Coal		57,424					29,455	22,000,000	648,015	2,109,724	3.67	71.62
20	Plant Unit Info	122	57,424	63.1%	94.0%	63.1%	11,285			648,015	2,109,724	3.67	
21	*St Johns 2*												
22	Coal		55,695					28,538	22,000,000	627,842	2,044,049	3.67	71.62
23	Plant Unit Info	122	55,695	61.2%	93.9%	61.2%	11,273			627,842	2,044,049	3.67	
24	*St Lucie 1*												
25	Nuclear		711,664					7,730,094	1,000,000	7,730,094	5,024,561	0.71	0.65
26	Plant Unit Info	981	711,664	97.5%	97.5%	97.5%	10,862			7,730,094	5,024,561	0.71	
27	*St Lucie 2*												
28	Nuclear		609,290					6,618,108	1,000,000	6,618,108	4,500,316	0.74	0.68
29	Plant Unit Info	840	609,290	97.5%	97.5%	97.5%	10,862			6,618,108	4,500,316	0.74	
30	*Space Coast*												
31	Solar		1,674					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	10	1,674	22.5%	N/A	49.1%	N/A			N/A	N/A	N/A	
33	*Turkey Point 1*												
34	Heavy Oil		15,014					28,628	6,400,000	183,219	2,671,812	17.80	93.33
35	Gas		20,504					250,207	1,000,000	250,207	995,391	4.85	3.98
36	Plant Unit Info	366	35,518	13.0%	95.4%	61.8%	12,203			433,426	3,667,203	10.32	
37	*Turkey Point 3*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

Line No.	(1) PLANT UNIT	(2) Net Capability (MW)	(3) Net Generation (MWH)	(4) Capacity Factor (%)	(5) Equivalent Availability Factor (%)	(6) Net Output Factor (%)	(7) Avg Net Heat Rate (BTU/KWH)	(8) Fuel Burned (Units)	(9) Fuel Heat Value (BTU/Unit)	(10) Fuel Burned (MMBTU)	(11) As Burned Fuel Cost ($)	(12) Fuel Cost per KWH (cents/KWH)	(13) Cost of Fuel ($/Unit)
1	Nuclear		588,299					6,607,778	1,000,000	6,607,778	4,559,370	0.78	0.69
2	Plant Unit Info	811	588,299	97.5%	97.5%	97.5%	11,232			6,607,778	4,559,370	0.78	
3	*Turkey Point 4*												
4	Nuclear		595,553					6,689,257	1,000,000	6,689,257	4,080,445	0.69	0.61
5	Plant Unit Info	821	595,553	97.5%	97.5%	97.5%	11,232			6,689,257	4,080,445	0.69	
6	*Turkey Point 5*												
7	Light Oil		2,039					2,445	5,830,000	14,257	261,187	12.81	106.81
8	Gas		559,481					3,912,786	1,000,000	3,912,786	15,555,910	2.78	3.98
9	Plant Unit Info	1,087	561,520	69.4%	95.1%	69.4%	6,994			3,927,043	15,817,097	2.82	
10	*WCEC 01*												
11	Light Oil		359					435	5,830,000	2,537	49,557	13.79	113.88
12	Gas		646,022					4,559,324	1,000,000	4,559,324	17,682,902	2.74	3.88
13	Plant Unit Info	1,182	646,381	73.5%	95.0%	73.5%	7,058			4,561,861	17,732,458	2.74	
14	*WCEC 02*												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		667,673					4,697,846	1,000,000	4,697,846	18,218,750	2.73	3.88
17	Plant Unit Info	1,172	667,673	76.6%	95.0%	76.6%	7,036			4,697,846	18,218,750	2.73	
18	*WCEC 03*												
19	Light Oil		0					0	0	0	0	0.00	0.00
20	Gas		658,713					4,634,142	1,000,000	4,634,142	17,971,359	2.73	3.88
21	Plant Unit Info	1,182	658,713	74.9%	95.0%	74.9%	7,035			4,634,142	17,971,359	2.73	
22	**System Totals**												
23	Plant Unit Info	24,887	11,332,674				8,187			92,786,044	277,561,133	2.45	
24													
25													
26													
27													
28													
29													
30													
31													
32													
33													
34													
35													
36													
37													

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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 - 2016**												
2	*Babcock PV Solar*												
3	Solar		8,178					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	75	8,178	15.1%	N/A	34.2%	N/A			N/A	N/A	N/A	
5	*Cedar Bay FPL*												
6	Light Oil		0					0	0	0	0	0.00	0.00
7	Coal		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
9	*CCEC 3*												
10	Light Oil		4,359					4,940	5,830,000	28,800	464,516	10.66	94.03
11	Gas		720,087					4,757,227	1,000,000	4,757,227	19,088,029	2.65	4.01
12	Plant Unit Info	1,223	724,446	82.3%	94.9%	82.3%	6,606			4,786,027	19,552,544	2.70	
13	*Citrus PV Solar*												
14	Solar		8,178					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	75	8,178	15.1%	N/A	34.2%	N/A			N/A	N/A	N/A	
16	*Desoto Solar*												
17	Solar		4,260					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	25	4,260	23.7%	N/A	51.6%	N/A			N/A	N/A	N/A	
19	*Everglades 1-12*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		315					5,511	1,000,000	5,511	22,112	7.02	4.01
22	Plant Unit Info	337	315	0.1%	95.4%	18.7%	17,495			5,511	22,112	7.02	
23	*Fort Myers 1-12*												
24	Light Oil		440					1,060	5,830,000	6,179	119,229	27.10	112.50
25	Plant Unit Info	556	440	0.1%	87.1%	7.2%	14,043			6,179	119,229	27.10	
26	*Fort Myers 2*												
27	Gas		659,644					4,911,009	1,000,000	4,911,009	19,705,180	2.99	4.01
28	Plant Unit Info	1,470	659,644	62.3%	95.1%	62.3%	7,445			4,911,009	19,705,180	2.99	
29	*Fort Myers 3A*												
30	Light Oil		0					0	0	0	0	0.00	0.00
31	Gas		3,385					39,099	1,000,000	39,099	156,873	4.63	4.01
32	Plant Unit Info	146	3,385	3.2%	95.4%	96.6%	11,551			39,099	156,873	4.63	
33	*Fort Myers 3B*												
34	Light Oil		0					0	0	0	0	0.00	0.00
35	Gas		2,243					25,958	1,000,000	25,958	104,148	4.64	4.01
36	Plant Unit Info	145	2,243	2.2%	95.4%	96.8%	11,573			25,958	104,148	4.64	
37	*Fort Myers 4A*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Light Oil		0					0	0	0	0	0.00	0.00
2	Gas		0					0	0	0	0	0.00	0.00
3	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
4	*Fort Myers 4B*												
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	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
8	*Lauderdale 1-24*												
9	Light Oil		0					0	0	0	0	0.00	0.00
10	Gas		450					7,628	1,000,000	7,628	30,606	6.80	4.01
11	Plant Unit Info	694	450	0.1%	95.4%	21.6%	16,951			7,628	30,606	6.80	
12	*Lauderdale 4*												
13	Light Oil		859					1,153	5,830,000	6,721	114,458	13.32	99.28
14	Gas		227,035					1,776,035	1,000,000	1,776,035	7,126,314	3.14	4.01
15	Plant Unit Info	431	227,894	73.4%	94.6%	73.4%	7,823			1,782,756	7,240,772	3.18	
16	*Lauderdale 5*												
17	Light Oil		363					487	5,830,000	2,839	48,348	13.33	99.28
18	Gas		231,080					1,808,147	1,000,000	1,808,147	7,255,155	3.14	4.01
19	Plant Unit Info	431	231,443	74.6%	94.7%	74.6%	7,825			1,810,986	7,303,503	3.16	
20	*Lauderdale 6 CT 1*												
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	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
24	*Lauderdale 6 CT 2*												
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	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
28	*Lauderdale 6 CT 3*												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
32	*Lauderdale 6 CT 4*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		0					0	0	0	0	0.00	0.00
35	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
36	*Lauderdale 6 CT 5*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
3	*Manatee 1*												
4	Heavy Oil		4,347					9,325	6,400,000	59,679	792,239	18.23	84.96
5	Gas		29,142					400,092	1,000,000	400,092	1,574,376	5.40	3.94
6	Plant Unit Info	780	33,489	6.0%	95.2%	44.2%	13,729			459,771	2,366,615	7.07	
7	*Manatee 2*												
8	Heavy Oil		2,217					4,822	6,400,000	30,861	409,680	18.48	84.96
9	Gas		5,654					78,710	1,000,000	78,710	308,490	5.46	3.92
10	Plant Unit Info	781	7,871	1.4%	95.1%	42.0%	13,921			109,571	718,170	9.12	
11	*Manatee 3*												
12	Gas		524,116					3,669,462	1,000,000	3,669,462	14,448,771	2.76	3.94
13	Plant Unit Info	1,087	524,116	67.0%	95.1%	67.0%	7,001			3,669,462	14,448,771	2.76	
14	*Manatee PV Solar*												
15	Solar		8,178					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	75	8,178	15.1%	N/A	34.2%	N/A			N/A	N/A	N/A	
17	*Martin 1*												
18	Heavy Oil		1,784					4,013	6,400,000	25,686	349,122	19.57	86.99
19	Gas		11,062					159,287	1,000,000	159,287	639,325	5.78	4.01
20	Plant Unit Info	797	12,846	2.2%	95.2%	39.3%	14,399			184,973	988,447	7.69	
21	*Martin 2*												
22	Heavy Oil		1,406					3,119	6,400,000	19,959	271,281	19.29	86.99
23	Gas		10,240					145,325	1,000,000	145,325	583,068	5.69	4.01
24	Plant Unit Info	767	11,646	2.1%	95.3%	44.7%	14,192			165,284	854,348	7.34	
25	*Martin 3*												
26	Gas		101,335					871,807	1,000,000	871,807	3,481,797	3.44	3.99
27	Plant Unit Info	453	101,335	31.1%	95.1%	77.4%	8,603			871,807	3,481,797	3.44	
28	*Martin 4*												
29	Gas		96,540					836,148	1,000,000	836,148	3,323,818	3.44	3.98
30	Plant Unit Info	447	96,540	30.0%	95.1%	75.0%	8,661			836,148	3,323,818	3.44	
31	*Martin 8*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		482,578					3,405,633	1,000,000	3,405,633	13,413,844	2.78	3.94
34	Plant Unit Info	1,007	482,578	66.6%	94.8%	66.6%	7,057			3,405,633	13,413,844	2.78	
35	*Martin 8 Solar*												
36	Solar		10,320					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	75	10,320	19.1%	N/A	35.3%	N/A			N/A	N/A	N/A	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	*PEEC*												
2	Light Oil		4,408					4,940	5,830,000	28,800	372,191	8.44	75.34
3	Gas		726,176					4,744,785	1,000,000	4,744,785	19,038,312	2.62	4.01
4	Plant Unit Info	1,234	730,584	82.2%	94.5%	82.2%	6,534			4,773,585	19,410,503	2.66	
5	*Riviera 5*												
6	Light Oil		9,177					10,518	5,830,000	61,318	1,178,487	12.84	112.05
7	Gas		626,939					4,189,252	1,000,000	4,189,252	16,809,319	2.68	4.01
8	Plant Unit Info	1,241	636,116	71.2%	94.9%	71.2%	6,682			4,250,570	17,987,806	2.83	
9	*Sanford 4*												
10	Gas		395,164					2,969,226	1,000,000	2,969,226	11,913,899	3.01	4.01
11	Plant Unit Info	955	395,164	57.5%	94.9%	57.5%	7,514			2,969,226	11,913,899	3.01	
12	*Sanford 5*												
13	Gas		377,175					2,819,137	1,000,000	2,819,137	11,311,723	3.00	4.01
14	Plant Unit Info	955	377,175	54.9%	77.4%	54.9%	7,474			2,819,137	11,311,723	3.00	
15	*Scherer 4*												
16	Coal		275,816					180,425	17,000,000	3,067,232	7,369,867	2.67	40.85
17	Plant Unit Info	598	275,816	64.1%	93.9%	64.1%	11,121			3,067,232	7,369,867	2.67	
18	*St Johns 1*												
19	Coal		50,693					25,922	22,000,000	570,294	1,833,198	3.62	70.72
20	Plant Unit Info	122	50,693	57.6%	94.0%	57.6%	11,250			570,294	1,833,198	3.62	
21	*St Johns 2*												
22	Coal		49,452					25,270	22,000,000	555,930	1,787,028	3.61	70.72
23	Plant Unit Info	122	49,452	56.2%	93.9%	56.2%	11,242			555,930	1,787,028	3.61	
24	*St Lucie 1*												
25	Nuclear		573,923					6,233,947	1,000,000	6,233,947	4,052,067	0.71	0.65
26	Plant Unit Info	981	573,923	81.3%	81.2%	97.5%	10,862			6,233,947	4,052,067	0.71	
27	*St Lucie 2*												
28	Nuclear		589,635					6,404,621	1,000,000	6,404,621	4,355,145	0.74	0.68
29	Plant Unit Info	840	589,635	97.5%	97.5%	97.5%	10,862			6,404,621	4,355,145	0.74	
30	*Space Coast*												
31	Solar		1,470					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	10	1,470	20.4%	N/A	44.6%	N/A			N/A	N/A	N/A	
33	*Turkey Point 1*												
34	Heavy Oil		5,342					10,943	6,400,000	70,035	1,021,293	19.12	93.33
35	Gas		19,708					258,398	1,000,000	258,398	1,036,818	5.26	4.01
36	Plant Unit Info	366	25,050	9.5%	95.4%	51.0%	13,111			328,433	2,058,112	8.22	
37	*Turkey Point 3*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

Line No.	(1) PLANT UNIT	(2) Net Capability (MW)	(3) Net Generation (MWH)	(4) Capacity Factor (%)	(5) Equivalent Availability Factor (%)	(6) Net Output Factor (%)	(7) Avg Net Heat Rate (BTU/KWH)	(8) Fuel Burned (Units)	(9) Fuel Heat Value (BTU/Unit)	(10) Fuel Burned (MMBTU)	(11) As Burned Fuel Cost ($)	(12) Fuel Cost per KWH (cents/KWH)	(13) Cost of Fuel ($/Unit)
1	Nuclear		569,322					6,394,624	1,000,000	6,394,624	4,412,293	0.78	0.69
2	Plant Unit Info	811	569,322	97.5%	97.5%	97.5%	11,232			6,394,624	4,412,293	0.78	
3	*Turkey Point 4*												
4	Nuclear		576,342					6,473,475	1,000,000	6,473,475	3,948,818	0.69	0.61
5	Plant Unit Info	821	576,342	97.5%	97.5%	97.5%	11,232			6,473,475	3,948,818	0.69	
6	*Turkey Point 5*												
7	Light Oil		1,061					1,274	5,830,000	7,430	136,117	12.83	106.81
8	Gas		545,269					3,819,638	1,000,000	3,819,638	15,326,034	2.81	4.01
9	Plant Unit Info	1,087	546,330	69.8%	95.1%	69.8%	7,005			3,827,068	15,462,151	2.83	
10	*WCEC 01*												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		660,233					4,625,414	1,000,000	4,625,414	18,121,355	2.74	3.92
13	Plant Unit Info	1,182	660,233	77.6%	95.0%	77.6%	7,006			4,625,414	18,121,355	2.74	
14	*WCEC 02*												
15	Light Oil		57					68	5,830,000	396	7,735	13.66	113.88
16	Gas		662,139					4,631,719	1,000,000	4,631,719	18,146,137	2.74	3.92
17	Plant Unit Info	1,172	662,196	78.5%	95.0%	78.5%	6,995			4,632,115	18,153,872	2.74	
18	*WCEC 03*												
19	Light Oil		0					0	0	0	0	0.00	0.00
20	Gas		660,129					4,629,545	1,000,000	4,629,545	18,137,607	2.75	3.92
21	Plant Unit Info	1,182	660,129	77.6%	95.0%	77.6%	7,013			4,629,545	18,137,607	2.75	
22	**System Totals**												
23	Plant Unit Info	25,556	10,539,425				8,125			85,633,019	254,146,222	2.41	
24													
25													
26													
27													
28													
29													
30													
31													
32													
33													
34													
35													
36													
37													

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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 - 2016**												
2	*Babcock PV Solar*												
3	Solar		8,184					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	75	8,184	14.7%	N/A	32.0%	N/A			N/A	N/A	N/A	
5	*Cedar Bay FPL*												
6	Light Oil		1,119					2,928	5,830,000	17,069	429,155	38.34	146.58
7	Coal		15,661					9,553	25,000,000	238,813	988,495	6.31	103.48
8	Plant Unit Info	250	16,780	9.0%	9.0%	69.2%	15,249			255,882	1,417,650	8.45	
9	*CCEC 3*												
10	Light Oil		2,020					2,264	5,830,000	13,200	212,903	10.54	94.03
11	Gas		839,527					5,484,698	1,000,000	5,484,698	22,358,491	2.66	4.08
12	Plant Unit Info	1,223	841,547	92.5%	94.9%	92.5%	6,533			5,497,898	22,571,394	2.68	
13	*Citrus PV Solar*												
14	Solar		8,184					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	75	8,184	14.7%	N/A	32.0%	N/A			N/A	N/A	N/A	
16	*Desoto Solar*												
17	Solar		4,092					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	25	4,092	22.0%	N/A	48.0%	N/A			N/A	N/A	N/A	
19	*Everglades 1-12*												
20	Light Oil		158					459	5,830,000	2,674	45,426	28.79	99.04
21	Gas		453					7,682	1,000,000	7,682	31,269	6.90	4.07
22	Plant Unit Info	342	611	0.2%	95.4%	29.8%	16,949			10,356	76,695	12.55	
23	*Fort Myers 1-12*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Plant Unit Info	0	0	0.0%	93.2%	0.0%	0			0	0	0.00	
26	*Fort Myers 2*												
27	Gas		729,925					5,386,273	1,000,000	5,386,273	21,958,213	3.01	4.08
28	Plant Unit Info	1,470	729,925	66.7%	88.1%	66.7%	7,379			5,386,273	21,958,213	3.01	
29	*Fort Myers 3A*												
30	Light Oil		0					0	0	0	0	0.00	0.00
31	Gas		3,562					40,831	1,000,000	40,831	166,490	4.67	4.08
32	Plant Unit Info	146	3,562	3.3%	95.4%	93.9%	11,463			40,831	166,490	4.67	
33	*Fort Myers 3B*												
34	Light Oil		0					0	0	0	0	0.00	0.00
35	Gas		566					6,530	1,000,000	6,530	26,581	4.70	4.07
36	Plant Unit Info	146	566	0.5%	95.4%	96.7%	11,537			6,530	26,581	4.70	
37	*Fort Myers 4A*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Light Oil		0					0	0	0	0	0.00	0.00
2	Gas		0					0	0	0	0	0.00	0.00
3	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
4	*Fort Myers 4B*												
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	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
8	*Lauderdale 1-24*												
9	Light Oil		0					0	0	0	0	0.00	0.00
10	Gas		3,173					53,842	1,000,000	53,842	219,702	6.92	4.08
11	Plant Unit Info	688	3,173	0.6%	95.4%	23.1%	16,969			53,842	219,702	6.92	
12	*Lauderdale 4*												
13	Light Oil		691					1,062	5,830,000	6,194	105,483	15.27	99.28
14	Gas		55,002					493,095	1,000,000	493,095	2,014,095	3.66	4.08
15	Plant Unit Info	431	55,693	17.4%	73.7%	81.3%	8,965			499,289	2,119,578	3.81	
16	*Lauderdale 5*												
17	Light Oil		837					1,268	5,830,000	7,393	125,902	15.04	99.28
18	Gas		65,703					580,162	1,000,000	580,162	2,368,786	3.61	4.08
19	Plant Unit Info	431	66,540	20.8%	94.7%	81.3%	8,830			587,555	2,494,688	3.75	
20	*Lauderdale 6 CT 1*												
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	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
24	*Lauderdale 6 CT 2*												
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	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
28	*Lauderdale 6 CT 3*												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
32	*Lauderdale 6 CT 4*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		0					0	0	0	0	0.00	0.00
35	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
36	*Lauderdale 6 CT 5*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
3	*Manatee 1*												
4	Heavy Oil		3,777					7,583	6,400,000	48,534	644,289	17.06	84.96
5	Gas		7,030					90,330	1,000,000	90,330	363,225	5.17	4.02
6	Plant Unit Info	781	10,807	1.9%	95.2%	57.7%	12,849			138,864	1,007,514	9.32	
7	*Manatee 2*												
8	Heavy Oil		3,430					7,233	6,400,000	46,290	614,500	17.91	84.96
9	Gas		9,275					125,152	1,000,000	125,152	503,072	5.42	4.02
10	Plant Unit Info	780	12,705	2.2%	95.1%	50.9%	13,494			171,442	1,117,572	8.80	
11	*Manatee 3*												
12	Gas		479,820					3,483,463	1,000,000	3,483,463	13,979,106	2.91	4.01
13	Plant Unit Info	1,087	479,820	59.3%	95.1%	80.0%	7,260			3,483,463	13,979,106	2.91	
14	*Manatee PV Solar*												
15	Solar		8,184					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	75	8,184	14.7%	N/A	32.0%	N/A			N/A	N/A	N/A	
17	*Martin 1*												
18	Heavy Oil		2,167					4,438	6,400,000	28,405	386,078	17.81	86.99
19	Gas		11,784					154,444	1,000,000	154,444	629,103	5.34	4.07
20	Plant Unit Info	795	13,951	2.4%	95.2%	51.6%	13,106			182,849	1,015,181	7.28	
21	*Martin 2*												
22	Heavy Oil		0					0	0	0	0	0.00	0.00
23	Gas		0					0	0	0	0	0.00	0.00
24	Plant Unit Info	0	0	0.0%	95.3%	0.0%	0			0	0	0.00	
25	*Martin 3*												
26	Gas		131,468					1,075,765	1,000,000	1,075,765	4,350,041	3.31	4.04
27	Plant Unit Info	453	131,468	39.0%	95.1%	77.6%	8,183			1,075,765	4,350,041	3.31	
28	*Martin 4*												
29	Gas		121,850					1,020,129	1,000,000	1,020,129	4,115,153	3.38	4.03
30	Plant Unit Info	447	121,850	36.6%	95.1%	81.6%	8,372			1,020,129	4,115,153	3.38	
31	*Martin 8*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		493,505					3,488,519	1,000,000	3,488,519	14,007,401	2.84	4.02
34	Plant Unit Info	1,007	493,505	65.9%	94.8%	65.9%	7,069			3,488,519	14,007,401	2.84	
35	*Martin 8 Solar*												
36	Solar		9,114					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	75	9,114	16.3%	N/A	30.1%	N/A			N/A	N/A	N/A	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	*PEEC*												
2	Light Oil		0					0	0	0	0	0.00	0.00
3	Gas		884,683					5,719,470	1,000,000	5,719,470	23,314,231	2.64	4.08
4	Plant Unit Info	1,234	884,683	94.5%	94.5%	96.4%	6,465			5,719,470	23,314,231	2.64	
5	*Riviera 5*												
6	Light Oil		2,479					2,771	5,830,000	16,157	310,526	12.53	112.05
7	Gas		857,045					5,585,496	1,000,000	5,585,496	22,769,135	2.66	4.08
8	Plant Unit Info	1,241	859,524	93.1%	94.9%	93.1%	6,517			5,601,653	23,079,661	2.69	
9	*Sanford 4*												
10	Gas		167,801					1,416,711	1,000,000	1,416,711	5,779,020	3.44	4.08
11	Plant Unit Info	955	167,801	23.6%	94.9%	65.6%	8,443			1,416,711	5,779,020	3.44	
12	*Sanford 5*												
13	Gas		271,333					2,128,324	1,000,000	2,128,324	8,673,535	3.20	4.08
14	Plant Unit Info	955	271,333	38.2%	82.8%	68.6%	7,844			2,128,324	8,673,535	3.20	
15	*Scherer 4*												
16	Coal		300,435					195,102	17,000,000	3,316,736	7,938,744	2.64	40.69
17	Plant Unit Info	598	300,435	67.5%	93.9%	67.5%	11,040			3,316,736	7,938,744	2.64	
18	*St Johns 1*												
19	Coal		54,686					27,973	22,000,000	615,412	1,962,159	3.59	70.14
20	Plant Unit Info	122	54,686	60.1%	94.0%	60.1%	11,254			615,412	1,962,159	3.59	
21	*St Johns 2*												
22	Coal		53,369					27,277	22,000,000	600,098	1,913,333	3.59	70.14
23	Plant Unit Info	122	53,369	58.7%	93.9%	58.7%	11,244			600,098	1,913,333	3.59	
24	*St Lucie 1*												
25	Nuclear		0					0	0	0	0	0.00	0.00
26	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
27	*St Lucie 2*												
28	Nuclear		609,290					6,618,108	1,000,000	6,618,108	4,500,316	0.74	0.68
29	Plant Unit Info	840	609,290	97.5%	97.5%	97.5%	10,862			6,618,108	4,500,316	0.74	
30	*Space Coast*												
31	Solar		1,395					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	10	1,395	18.8%	N/A	45.0%	N/A			N/A	N/A	N/A	
33	*Turkey Point 1*												
34	Heavy Oil		3,390					7,041	6,400,000	45,063	657,136	19.38	93.33
35	Gas		13,128					174,501	1,000,000	174,501	712,706	5.43	4.08
36	Plant Unit Info	366	16,518	6.1%	95.4%	49.5%	13,292			219,564	1,369,842	8.29	
37	*Turkey Point 3*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

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)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	Nuclear		588,299					6,607,778	1,000,000	6,607,778	4,559,370	0.78	0.69
2	Plant Unit Info	811	588,299	97.5%	97.5%	97.5%	11,232			6,607,778	4,559,370	0.78	
3	*Turkey Point 4*												
4	Nuclear		595,553					6,689,257	1,000,000	6,689,257	4,080,445	0.69	0.61
5	Plant Unit Info	821	595,553	97.5%	97.5%	97.5%	11,232			6,689,257	4,080,445	0.69	
6	*Turkey Point 5*												
7	Light Oil		1,196					1,504	5,830,000	8,767	160,611	13.43	106.81
8	Gas		408,188					2,991,784	1,000,000	2,991,784	12,199,874	2.99	4.08
9	Plant Unit Info	1,087	409,384	50.6%	95.1%	78.0%	7,329			3,000,551	12,360,484	3.02	
10	*WCEC 01*												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		741,050					5,127,388	1,000,000	5,127,388	20,454,529	2.76	3.99
13	Plant Unit Info	1,182	741,050	84.3%	95.0%	84.3%	6,919			5,127,388	20,454,529	2.76	
14	*WCEC 02*												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		700,895					4,879,252	1,000,000	4,879,252	19,464,559	2.78	3.99
17	Plant Unit Info	1,172	700,895	80.4%	94.0%	80.4%	6,961			4,879,252	19,464,559	2.78	
18	*WCEC 03*												
19	Light Oil		0					0	0	0	0	0.00	0.00
20	Gas		616,560					4,350,607	1,000,000	4,350,607	17,355,305	2.81	3.99
21	Plant Unit Info	1,182	616,560	70.1%	95.0%	70.1%	7,056			4,350,607	17,355,305	2.81	
22	**System Totals**												
23	Plant Unit Info	23,500	9,891,036				7,966			78,790,396	247,448,493	2.50	
24													
25													
26													
27													
28													
29													
30													
31													
32													
33													
34													
35													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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 - 2016**												
2	*Babcock PV Solar*												
3	Solar		7,020					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	75	7,020	13.0%	N/A	31.2%	N/A			N/A	N/A	N/A	
5	*Cedar Bay FPL*												
6	Light Oil		0					0	0	0	0	0.00	0.00
7	Coal		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
9	*CCEC 3*												
10	Light Oil		6,374					7,204	5,830,000	42,000	677,419	10.63	94.03
11	Gas		710,433					4,681,528	1,000,000	4,681,528	20,526,451	2.89	4.38
12	Plant Unit Info	1,234	716,807	80.7%	94.9%	80.7%	6,590			4,723,528	21,203,870	2.96	
13	*Citrus PV Solar*												
14	Solar		7,020					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	75	7,020	13.0%	N/A	31.2%	N/A			N/A	N/A	N/A	
16	*Desoto Solar*												
17	Solar		3,510					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	25	3,510	19.5%	N/A	46.8%	N/A			N/A	N/A	N/A	
19	*Everglades 1-12*												
20	Light Oil		114					327	5,830,000	1,907	32,396	28.52	99.04
21	Gas		47					796	1,000,000	796	3,492	7.36	4.39
22	Plant Unit Info	319	161	0.1%	95.4%	25.2%	16,789			2,703	35,888	22.29	
23	*Fort Myers 1-12*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Plant Unit Info	0	0	0.0%	95.4%	0.0%	0			0	0	0.00	
26	*Fort Myers 2*												
27	Gas		669,427					4,975,091	1,000,000	4,975,091	21,815,502	3.26	4.38
28	Plant Unit Info	1,669	669,427	55.7%	82.9%	55.7%	7,432			4,975,091	21,815,502	3.26	
29	*Fort Myers 3A*												
30	Light Oil		0					0	0	0	0	0.00	0.00
31	Gas		597					6,711	1,000,000	6,711	29,439	4.93	4.39
32	Plant Unit Info	184	597	0.5%	95.4%	81.0%	11,241			6,711	29,439	4.93	
33	*Fort Myers 3B*												
34	Light 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	0	0	0.0%	95.4%	0.0%	0			0	0	0.00	
37	*Fort Myers 4A*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Light Oil		0					0	0	0	0	0.00	0.00
2	Gas		0					0	0	0	0	0.00	0.00
3	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
4	*Fort Myers 4B*												
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	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
8	*Lauderdale 1-24*												
9	Light Oil		0					0	0	0	0	0.00	0.00
10	Gas		4,276					72,596	1,000,000	72,596	318,457	7.45	4.39
11	Plant Unit Info	683	4,276	0.9%	95.4%	22.4%	16,978			72,596	318,457	7.45	
12	*Lauderdale 4*												
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	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
16	*Lauderdale 5*												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		27,285					237,730	1,000,000	237,730	1,040,489	3.81	4.38
19	Plant Unit Info	441	27,285	8.6%	94.7%	83.6%	8,713			237,730	1,040,489	3.81	
20	*Lauderdale 6 CT 1*												
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	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
24	*Lauderdale 6 CT 2*												
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	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
28	*Lauderdale 6 CT 3*												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
32	*Lauderdale 6 CT 4*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		0					0	0	0	0	0.00	0.00
35	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
36	*Lauderdale 6 CT 5*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
3	*Manatee 1*												
4	Heavy Oil		1,195					2,423	6,400,000	15,505	205,829	17.23	84.96
5	Gas		6,425					83,393	1,000,000	83,393	359,074	5.59	4.31
6	Plant Unit Info	790	7,619	1.3%	95.2%	53.6%	12,980			98,898	564,903	7.41	
7	*Manatee 2*												
8	Heavy Oil		1,201					2,506	6,400,000	16,041	212,944	17.73	84.96
9	Gas		5,358					71,554	1,000,000	71,554	308,481	5.76	4.31
10	Plant Unit Info	792	6,559	1.2%	95.1%	51.8%	13,355			87,595	521,426	7.95	
11	*Manatee 3*												
12	Gas		492,580					3,534,653	1,000,000	3,534,653	15,274,481	3.10	4.32
13	Plant Unit Info	1,158	492,580	59.1%	95.1%	82.0%	7,176			3,534,653	15,274,481	3.10	
14	*Manatee PV Solar*												
15	Solar		7,020					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	75	7,020	13.0%	N/A	31.2%	N/A			N/A	N/A	N/A	
17	*Martin 1*												
18	Heavy Oil		0					0	0	0	0	0.00	0.00
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	0	0	0.0%	95.2%	0.0%	0			0	0	0.00	
21	*Martin 2*												
22	Heavy Oil		0					0	0	0	0	0.00	0.00
23	Gas		0					0	0	0	0	0.00	0.00
24	Plant Unit Info	0	0	0.0%	95.3%	0.0%	0			0	0	0.00	
25	*Martin 3*												
26	Gas		103,007					851,830	1,000,000	851,830	3,688,176	3.58	4.33
27	Plant Unit Info	479	103,007	29.9%	95.1%	54.7%	8,270			851,830	3,688,176	3.58	
28	*Martin 4*												
29	Gas		84,292					712,607	1,000,000	712,607	3,083,071	3.66	4.33
30	Plant Unit Info	433	84,292	27.0%	95.1%	89.3%	8,454			712,607	3,083,071	3.66	
31	*Martin 8*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		386,131					2,879,886	1,000,000	2,879,886	12,446,763	3.22	4.32
34	Plant Unit Info	1,112	386,131	48.2%	94.8%	74.2%	7,458			2,879,886	12,446,763	3.22	
35	*Martin 8 Solar*												
36	Solar		6,510					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	75	6,510	12.1%	N/A	20.7%	N/A			N/A	N/A	N/A	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

Line No.	(1) PLANT UNIT	(2) Net Capability (MW)	(3) Net Generation (MWH)	(4) Capacity Factor (%)	(5) Equivalent Availability Factor (%)	(6) Net Output Factor (%)	(7) Avg Net Heat Rate (BTU/KWH)	(8) Fuel Burned (Units)	(9) Fuel Heat Value (BTU/Unit)	(10) Fuel Burned (MMBTU)	(11) As Burned Fuel Cost ($)	(12) Fuel Cost per KWH (cents/KWH)	(13) Cost of Fuel ($/Unit)
1	*PEEC*												
2	Light Oil		5,361					6,038	5,830,000	35,200	454,900	8.48	75.34
3	Gas		469,002					3,079,272	1,000,000	3,079,272	13,497,996	2.88	4.38
4	Plant Unit Info	1,216	474,363	54.2%	57.8%	85.5%	6,566			3,114,472	13,952,896	2.94	
5	*Riviera 5*												
6	Light Oil		8,000					9,057	5,830,000	52,800	1,014,778	12.68	112.05
7	Gas		718,466					4,741,620	1,000,000	4,741,620	20,790,205	2.89	4.38
8	Plant Unit Info	1,216	726,466	83.0%	94.9%	83.0%	6,600			4,794,420	21,804,982	3.00	
9	*Sanford 4*												
10	Gas		0					0	0	0	0	0.00	0.00
11	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
12	*Sanford 5*												
13	Gas		206,426					1,700,326	1,000,000	1,700,326	7,453,729	3.61	4.38
14	Plant Unit Info	1,020	206,426	28.1%	94.9%	69.3%	8,237			1,700,326	7,453,729	3.61	
15	*Scherer 4*												
16	Coal		289,308					186,742	17,000,000	3,174,612	7,595,909	2.63	40.68
17	Plant Unit Info	599	289,308	67.1%	93.9%	67.1%	10,973			3,174,612	7,595,909	2.63	
18	*St Johns 1*												
19	Coal		49,874					25,200	22,000,000	554,407	1,736,374	3.48	68.90
20	Plant Unit Info	125	49,874	55.3%	94.0%	55.3%	11,116			554,407	1,736,374	3.48	
21	*St Johns 2*												
22	Coal		48,154					24,299	22,000,000	534,585	1,674,293	3.48	68.90
23	Plant Unit Info	125	48,154	53.4%	93.9%	53.4%	11,101			534,585	1,674,293	3.48	
24	*St Lucie 1*												
25	Nuclear		657,619					7,143,060	1,000,000	7,143,060	4,500,126	0.68	0.63
26	Plant Unit Info	1,004	657,619	91.0%	91.0%	97.5%	10,862			7,143,060	4,500,126	0.68	
27	*St Lucie 2*												
28	Nuclear		603,236					6,552,344	1,000,000	6,552,344	4,455,592	0.74	0.68
29	Plant Unit Info	859	603,236	97.5%	97.5%	97.5%	10,862			6,552,344	4,455,592	0.74	
30	*Space Coast*												
31	Solar		1,170					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	10	1,170	16.3%	N/A	43.3%	N/A			N/A	N/A	N/A	
33	*Turkey Point 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	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
37	*Turkey Point 3*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

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)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	Nuclear		588,978					6,615,404	1,000,000	6,615,404	4,564,627	0.78	0.69
2	Plant Unit Info	839	588,978	97.5%	97.5%	97.5%	11,232			6,615,404	4,564,627	0.78	
3	*Turkey Point 4*												
4	Nuclear		595,296					6,686,369	1,000,000	6,686,369	4,078,682	0.69	0.61
5	Plant Unit Info	848	595,296	97.5%	97.5%	97.5%	11,232			6,686,369	4,078,682	0.69	
6	*Turkey Point 5*												
7	Light Oil		0					0	0	0	0	0.00	0.00
8	Gas		180,681					1,355,478	1,000,000	1,355,478	5,939,534	3.29	4.38
9	Plant Unit Info	1,155	180,681	21.7%	95.1%	67.4%	7,502			1,355,478	5,939,534	3.29	
10	*WCEC 01*												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		379,669					2,801,029	1,000,000	2,801,029	12,080,201	3.18	4.31
13	Plant Unit Info	1,208	379,669	43.7%	95.0%	77.6%	7,378			2,801,029	12,080,201	3.18	
14	*WCEC 02*												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		389,217					2,753,662	1,000,000	2,753,662	11,880,076	3.05	4.31
17	Plant Unit Info	1,198	389,217	45.1%	53.9%	61.5%	7,075			2,753,662	11,880,076	3.05	
18	*WCEC 03*												
19	Light Oil		0					0	0	0	0	0.00	0.00
20	Gas		678,124					4,703,458	1,000,000	4,703,458	20,293,875	2.99	4.31
21	Plant Unit Info	1,208	678,124	78.0%	95.0%	78.0%	6,936			4,703,458	20,293,875	2.99	
22	**System Totals**												
23	Plant Unit Info	22,249	8,398,402				8,414			70,667,454	202,033,361	2.41	
24													
25													
26													
27													
28													
29													
30													
31													
32													
33													
34													
35													
36													
37													

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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 - 2016**												
2	*Babcock PV Solar*												
3	Solar		6,324					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	75	6,324	11.3%	N/A	30.2%	N/A			N/A	N/A	N/A	
5	*Cedar Bay FPL*												
6	Light Oil		0					0	0	0	0	0.00	0.00
7	Coal		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
9	*CCEC 3*												
10	Light Oil		10,297					11,732	5,830,000	68,400	1,035,427	10.06	88.25
11	Gas		693,007					4,603,566	1,000,000	4,603,566	21,023,632	3.03	4.57
12	Plant Unit Info	1,234	703,304	76.6%	94.9%	76.6%	6,643			4,671,966	22,059,059	3.14	
13	*Citrus PV Solar*												
14	Solar		6,324					N/A	N/A	N/A	N/A	N/A	N/A
15	Plant Unit Info	75	6,324	11.3%	N/A	30.2%	N/A			N/A	N/A	N/A	
16	*Desoto Solar*												
17	Solar		3,193					N/A	N/A	N/A	N/A	N/A	N/A
18	Plant Unit Info	25	3,193	17.2%	N/A	45.8%	N/A			N/A	N/A	N/A	
19	*Everglades 1-12*												
20	Light Oil		0					0	0	0	0	0.00	0.00
21	Gas		0					0	0	0	0	0.00	0.00
22	Plant Unit Info	0	0	0.0%	95.4%	0.0%	0			0	0	0.00	
23	*Fort Myers 1-12*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Plant Unit Info	0	0	0.0%	95.4%	0.0%	0			0	0	0.00	
26	*Fort Myers 2*												
27	Gas		604,514					4,535,358	1,000,000	4,535,358	20,713,032	3.43	4.57
28	Plant Unit Info	1,669	604,514	48.7%	95.1%	48.7%	7,502			4,535,358	20,713,032	3.43	
29	*Fort Myers 3A*												
30	Light Oil		0					0	0	0	0	0.00	0.00
31	Gas		0					0	0	0	0	0.00	0.00
32	Plant Unit Info	0	0	0.0%	95.4%	0.0%	0			0	0	0.00	
33	*Fort Myers 3B*												
34	Light 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	0	0	0.0%	95.4%	0.0%	0			0	0	0.00	
37	*Fort Myers 4A*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Light Oil		0					0	0	0	0	0.00	0.00
2	Gas		4,200					46,789	1,000,000	46,789	213,817	5.09	4.57
3	Plant Unit Info	223	4,200	2.5%	97.5%	67.2%	11,140			46,789	213,817	5.09	
4	*Fort Myers 4B*												
5	Light Oil		0					0	0	0	0	0.00	0.00
6	Gas		1,200					13,460	1,000,000	13,460	61,509	5.13	4.57
7	Plant Unit Info	224	1,200	0.7%	97.5%	67.0%	11,217			13,460	61,509	5.13	
8	*Lauderdale 1-24*												
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	0	0	0.0%	95.4%	0.0%	0			0	0	0.00	
12	*Lauderdale 4*												
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	0	0	0.0%	33.4%	0.0%	0			0	0	0.00	
16	*Lauderdale 5*												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		13,797					132,575	1,000,000	132,575	605,839	4.39	4.57
19	Plant Unit Info	440	13,797	4.2%	94.7%	65.3%	9,609			132,575	605,839	4.39	
20	*Lauderdale 6 CT 1*												
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	0	0	0.0%	97.5%	0.0%	0			0	0	0.00	
24	*Lauderdale 6 CT 2*												
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	0	0	0.0%	97.5%	0.0%	0			0	0	0.00	
28	*Lauderdale 6 CT 3*												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		0					0	0	0	0	0.00	0.00
31	Plant Unit Info	0	0	0.0%	97.5%	0.0%	0			0	0	0.00	
32	*Lauderdale 6 CT 4*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		0					0	0	0	0	0.00	0.00
35	Plant Unit Info	0	0	0.0%	97.5%	0.0%	0			0	0	0.00	
36	*Lauderdale 6 CT 5*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Gas		0					0	0	0	0	0.00	0.00
2	Plant Unit Info	0	0	0.0%	97.5%	0.0%	0			0	0	0.00	
3	*Manatee 1*												
4	Heavy Oil		0					0	0	0	0	0.00	0.00
5	Gas		0					0	0	0	0	0.00	0.00
6	Plant Unit Info	0	0	0.0%	95.2%	0.0%	0			0	0	0.00	
7	*Manatee 2*												
8	Heavy 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	0	0	0.0%	95.1%	0.0%	0			0	0	0.00	
11	*Manatee 3*												
12	Gas		290,712					2,197,975	1,000,000	2,197,975	9,887,806	3.40	4.50
13	Plant Unit Info	1,158	290,712	33.7%	95.1%	66.6%	7,561			2,197,975	9,887,806	3.40	
14	*Manatee PV Solar*												
15	Solar		6,324					N/A	N/A	N/A	N/A	N/A	N/A
16	Plant Unit Info	75	6,324	11.3%	N/A	30.2%	N/A			N/A	N/A	N/A	
17	*Martin 1*												
18	Heavy Oil		0					0	0	0	0	0.00	0.00
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	0	0	0.0%	95.2%	0.0%	0			0	0	0.00	
21	*Martin 2*												
22	Heavy Oil		0					0	0	0	0	0.00	0.00
23	Gas		0					0	0	0	0	0.00	0.00
24	Plant Unit Info	0	0	0.0%	95.3%	0.0%	0			0	0	0.00	
25	*Martin 3*												
26	Gas		7,127					65,684	1,000,000	65,684	296,466	4.16	4.51
27	Plant Unit Info	479	7,127	2.0%	95.1%	62.0%	9,216			65,684	296,466	4.16	
28	*Martin 4*												
29	Gas		5,520					49,898	1,000,000	49,898	225,039	4.08	4.51
30	Plant Unit Info	434	5,520	1.7%	95.1%	50.9%	9,039			49,898	225,039	4.08	
31	*Martin 8*												
32	Light Oil		0					0	0	0	0	0.00	0.00
33	Gas		465,066					3,250,180	1,000,000	3,250,180	14,601,358	3.14	4.49
34	Plant Unit Info	1,112	465,066	56.2%	77.1%	56.2%	6,989			3,250,180	14,601,358	3.14	
35	*Martin 8 Solar*												
36	Solar		5,425					N/A	N/A	N/A	N/A	N/A	N/A
37	Plant Unit Info	75	5,425	9.7%	N/A	17.9%	N/A			N/A	N/A	N/A	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	*PEEC*												
2	Light Oil		5,338					5,969	5,830,000	34,800	449,731	8.42	75.34
3	Gas		802,873					5,233,742	1,000,000	5,233,742	23,902,528	2.98	4.57
4	Plant Unit Info	1,216	808,211	89.3%	94.5%	89.3%	6,519			5,268,542	24,352,259	3.01	
5	*Riviera 5*												
6	Light Oil		9,678					11,115	5,830,000	64,800	1,245,409	12.87	112.05
7	Gas		599,902					4,016,581	1,000,000	4,016,581	18,341,919	3.06	4.57
8	Plant Unit Info	1,216	609,580	67.4%	94.9%	67.4%	6,695			4,081,381	19,587,327	3.21	
9	*Sanford 4*												
10	Gas		4,089					39,798	1,000,000	39,798	181,867	4.45	4.57
11	Plant Unit Info	1,018	4,089	0.5%	43.3%	33.5%	9,733			39,798	181,867	4.45	
12	*Sanford 5*												
13	Gas		43,034					374,774	1,000,000	374,774	1,712,635	3.98	4.57
14	Plant Unit Info	1,020	43,034	5.7%	94.9%	49.6%	8,709			374,774	1,712,635	3.98	
15	*Scherer 4*												
16	Coal		273,504					178,806	17,000,000	3,039,710	7,287,241	2.66	40.75
17	Plant Unit Info	599	273,504	61.4%	93.9%	61.4%	11,114			3,039,710	7,287,241	2.66	
18	*St Johns 1*												
19	Coal		51,014					25,746	22,000,000	566,410	1,761,695	3.45	68.43
20	Plant Unit Info	125	51,014	54.8%	94.0%	54.8%	11,103			566,410	1,761,695	3.45	
21	*St Johns 2*												
22	Coal		49,547					24,966	22,000,000	549,250	1,708,324	3.45	68.43
23	Plant Unit Info	125	49,547	53.2%	93.9%	53.2%	11,085			549,250	1,708,324	3.45	
24	*St Lucie 1*												
25	Nuclear		728,079					7,908,389	1,000,000	7,908,389	4,982,282	0.68	0.63
26	Plant Unit Info	1,004	728,079	97.5%	97.5%	97.5%	10,862			7,908,389	4,982,282	0.68	
27	*St Lucie 2*												
28	Nuclear		623,343					6,770,755	1,000,000	6,770,755	4,604,112	0.74	0.68
29	Plant Unit Info	859	623,343	97.5%	97.5%	97.5%	10,862			6,770,755	4,604,112	0.74	
30	*Space Coast*												
31	Solar		1,085					N/A	N/A	N/A	N/A	N/A	N/A
32	Plant Unit Info	10	1,085	14.6%	N/A	38.9%	N/A			N/A	N/A	N/A	
33	*Turkey Point 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	0	0	0.0%	0.0%	0.0%	0			0	0	0.00	
37	*Turkey Point 3*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

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)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	Nuclear		608,611					6,835,918	1,000,000	6,835,918	4,716,781	0.78	0.69
2	Plant Unit Info	839	608,611	97.5%	97.5%	97.5%	11,232			6,835,918	4,716,781	0.78	
3	*Turkey Point 4*												
4	Nuclear		615,139					6,909,248	1,000,000	6,909,248	4,214,638	0.69	0.61
5	Plant Unit Info	848	615,139	97.5%	97.5%	97.5%	11,232			6,909,248	4,214,638	0.69	
6	*Turkey Point 5*												
7	Light Oil		1,003					1,333	5,830,000	7,774	129,686	12.93	97.26
8	Gas		134,055					1,039,044	1,000,000	1,039,044	4,748,200	3.54	4.57
9	Plant Unit Info	1,155	135,058	15.7%	95.1%	51.5%	7,751			1,046,818	4,877,885	3.61	
10	*WCEC 01*												
11	Light Oil		0					0	0	0	0	0.00	0.00
12	Gas		630,649					4,425,984	1,000,000	4,425,984	19,875,873	3.15	4.49
13	Plant Unit Info	1,208	630,649	70.2%	95.0%	70.2%	7,018			4,425,984	19,875,873	3.15	
14	*WCEC 02*												
15	Light Oil		0					0	0	0	0	0.00	0.00
16	Gas		687,806					4,779,132	1,000,000	4,779,132	21,461,471	3.12	4.49
17	Plant Unit Info	1,198	687,806	77.2%	95.0%	77.2%	6,948			4,779,132	21,461,471	3.12	
18	*WCEC 03*												
19	Light Oil		0					0	0	0	0	0.00	0.00
20	Gas		648,946					4,540,339	1,000,000	4,540,339	20,388,825	3.14	4.49
21	Plant Unit Info	1,208	648,946	72.2%	95.0%	72.2%	6,996			4,540,339	20,388,825	3.14	
22	**System Totals**												
23	Plant Unit Info	20,947	8,640,725				8,344			72,100,333	210,377,139	2.43	
24													
25													
26													
27													
28													
29													
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31													
32													
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35													
36													
37													

FLORIDA POWER & LIGHT COMPANY
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

Line No.	(1)	(2) Jul - 2016	(3) Aug - 2016	(4) Sep - 2016	(5) Oct - 2016	(6) Nov - 2016	(7) Dec - 2016	(8) Jul:Dec - 2016
1	**#6 Heavy Oil (BBLS)**							
2	Purchases							
3	Units	0	255,000	0	0	0	875,000	1,130,000
4	Unit Cost	0.0000	51.6157	0.0000	0.0000	0.0000	52.1851	52.0566
5	Amount	$0	$13,162,000	$0	$0	$0	$45,662,000	$58,824,000
6	Burned							
7	Units	97,728	107,684	32,222	26,296	4,929	0	268,859
8	Unit Cost	92.2233	87.8581	88.2511	87.5432	84.9600	0.0000	89.4080
9	Amount	$9,012,839	$9,460,877	$2,843,615	$2,302,004	$418,773	$0	$24,038,108
10	Ending Inventory							
11	Units	1,797,337	1,944,653	1,912,431	1,886,135	1,881,206	2,756,206	2,756,206
12	Unit Cost	91.9950	86.9286	86.9067	86.8983	86.9033	75.8815	75.8815
13	Amount	$165,346,000	$169,046,000	$166,203,000	$163,902,000	$163,483,000	$209,145,000	$209,145,000
14	**#2 Light Oil (BBLS)**							
15	Purchases							
16	Units	38,000	7,000	35,587	0	23,249	33,530	137,366
17	Unit Cost	68.5263	65.7143	66.5970	0.0000	68.3915	69.2215	68.0300
18	Amount	$2,604,000	$460,000	$2,370,000	$0	$1,590,000	$2,321,000	$9,345,000
19	Burned							
20	Units	16,083	18,567	24,440	12,256	22,626	30,150	124,121
21	Unit Cost	124.4833	123.0492	99.8821	113.4118	96.3288	94.8677	106.0055
22	Amount	$2,002,109	$2,284,599	$2,441,081	$1,390,005	$2,179,492	$2,860,252	$13,157,538
23	Ending Inventory							
24	Units	1,284,161	1,272,594	1,283,742	1,271,485	1,272,108	1,275,488	1,275,488
25	Unit Cost	106.2803	105.8122	104.8381	104.7554	104.2411	103.5415	103.5415
26	Amount	$136,481,000	$134,656,000	$134,585,000	$133,195,000	$132,606,000	$132,066,000	$132,066,000
27	**Coal - SJRPP (TONS)**							
28	Purchases							
29	Units	54,322	54,322	54,322	54,322	54,322	54,322	325,934
30	Unit Cost	65.2402	70.6339	69.0508	69.0508	66.5840	67.4860	68.0076
31	Amount	$3,544,000	$3,837,000	$3,751,000	$3,751,000	$3,617,000	$3,666,000	$22,166,000
32	Burned							
33	Units	61,287	57,994	51,192	55,250	49,500	50,712	325,934
34	Unit Cost	72.1507	71.6248	70.7186	70.1441	68.9029	68.4262	70.4193
35	Amount	$4,421,880	$4,153,773	$3,620,226	$3,875,492	$3,410,667	$3,470,018	$22,952,057
36	Ending Inventory							
37	Units	103,171	99,499	102,630	101,702	106,524	110,135	110,135
38	Unit Cost	72.1523	71.6285	70.7202	70.1463	68.9043	68.4251	68.4251
39	Amount	$7,444,000	$7,127,000	$7,258,000	$7,134,000	$7,340,000	$7,536,000	$7,536,000
40								

FLORIDA POWER & LIGHT COMPANY
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

Line No.	(1)	(2) Jul - 2016	(3) Aug - 2016	(4) Sep - 2016	(5) Oct - 2016	(6) Nov - 2016	(7) Dec - 2016	(8) Jul:Dec - 2016
1	**Coal - Scherer (MMBTU)**							
2	Purchases							
3	Units	3,283,279	3,283,279	3,283,279	3,283,279	3,283,279	3,283,279	19,699,671
4	Unit Cost	2.3547	2.3760	2.3638	2.3760	2.3912	2.4064	2.3780
5	Amount	$7,731,000	$7,801,000	$7,761,000	$7,801,000	$7,851,000	$7,901,000	$46,846,000
6	Burned							
7	Units	3,755,292	3,346,089	3,067,232	3,316,736	3,174,612	3,039,710	19,699,671
8	Unit Cost	2.4497	2.4239	2.4028	2.3935	2.3927	2.3973	2.4113
9	Amount	$9,199,379	$8,110,700	$7,369,867	$7,938,744	$7,595,909	$7,287,241	$47,501,841
10	Ending Inventory							
11	Units	6,113,477	6,050,666	6,266,713	6,233,255	6,341,922	6,585,490	6,585,490
12	Unit Cost	2.4497	2.4239	2.4027	2.3936	2.3927	2.3974	2.3974
13	Amount	$14,976,000	$14,666,000	$15,057,000	$14,920,000	$15,174,000	$15,788,000	$15,788,000
14	**Coal - Cedar Bay (TONS)**							
15	Purchases							
16	Units	0	0	0	0	0	0	0
17	Unit Cost	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
18	Amount	$0	$0	$0	$0	$0	$0	$0
19	Burned							
20	Units	9,533	9,553	0	9,553	0	0	28,638
21	Unit Cost	103.4800	103.4800	0.0000	103.4800	0.0000	0.0000	103.4800
22	Amount	$986,433	$988,495	$0	$988,495	$0	$0	$2,963,423
23	Ending Inventory							
24	Units	19,105	9,553	9,553	0	0	0	0
25	Unit Cost	103.4805	103.4282	103.4282	0.0000	0.0000	0.0000	0.0000
26	Amount	$1,977,000	$988,000	$988,000	$0	$0	$0	$0
27	**Gas (MCF)**							
28	Burned							
29	Units	58,192,298	59,482,630	55,584,192	53,864,448	39,243,220	39,344,879	305,711,667
30	Unit Cost	4.0491	3.9406	3.9778	4.0437	4.3531	4.5302	4.1150
31	Amount	$235,624,455	$234,397,997	$221,103,110	$217,813,622	$170,829,493	$178,241,815	$1,258,010,493
32	**Nuclear (Other)**							
33	Burned							
34	Units	27,645,237	27,645,237	25,506,668	19,915,143	26,997,177	28,424,310	156,133,772
35	Unit Cost	0.6571	0.6571	0.6574	0.6598	0.6519	0.6515	0.6556
36	Amount	$18,164,692	$18,164,692	$16,768,323	$13,140,131	$17,599,027	$18,517,813	$102,354,677
37								
38								
39								
40								
41								

FLORIDA POWER & LIGHT COMPANY
POWER SOLD

SCHEDULE: E6

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

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(4) * Col(5))	Total Cost ($) (Col(4) * Col(6))	Gain from Off System Sales ($)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1									
2	**July Estimated**								
3	Off System	OS	68,700	68,700	4.249	5.562	$2,918,846	$3,821,396	$661,300
4	St Lucie Reliability Sales		53,003	53,003	0.712	0.712	$377,269	$377,269	$0
5	**Total July Estimated**		121,703	121,703	2.708	3.450	$3,296,115	$4,198,665	$661,300
6									
7	**August Estimated**								
8	Off System	OS	65,200	65,200	4.039	5.370	$2,633,725	$3,501,275	$636,800
9	St Lucie Reliability Sales		53,003	53,003	0.712	0.712	$377,269	$377,269	$0
10	**Total August Estimated**		118,203	118,203	2.547	3.281	$3,010,994	$3,878,544	$636,800
11									
12	**September Estimated**								
13	Off System	OS	73,000	73,000	3.111	4.412	$2,270,925	$3,220,675	$690,175
14	St Lucie Reliability Sales		42,744	42,744	0.712	0.712	$304,249	$304,249	$0
15	**Total September Estimated**		115,744	115,744	2.225	3.045	$2,575,173	$3,524,923	$690,175
16									
17	**October Estimated**								
18	Off System	OS	66,000	66,000	2.675	3.516	$1,765,432	$2,320,432	$347,950
19	St Lucie Reliability Sales		0	0	0.000	0.000	$0	$0	$0
20	**Total October Estimated**		66,000	66,000	2.675	3.516	$1,765,432	$2,320,432	$347,950
21									
22	**November Estimated**								
23	Off System	OS	74,500	74,500	2.753	3.553	$2,050,696	$2,646,696	$366,200
24	St Lucie Reliability Sales		48,978	48,978	0.703	0.703	$344,415	$344,415	$0
25	**Total November Estimated**		123,478	123,478	1.940	2.422	$2,395,112	$2,991,112	$366,200
26									
27	**December Estimated**								
28	Off System	OS	108,000	108,000	2.354	3.164	$2,542,112	$3,417,112	$547,200
29	St Lucie Reliability Sales		54,226	54,226	0.703	0.703	$381,317	$381,317	$0
30	**Total December Estimated**		162,226	162,226	1.802	2.341	$2,923,429	$3,798,429	$547,200
31									
32	**Period Total**								
33	Off System	OS	455,400	455,400	3.114	4.156	$14,181,736	$18,927,586	$3,249,625
34	St Lucie Reliability Sales		251,954	251,954	0.708	0.708	$1,784,519	$1,784,519	$0
35	**Total Period Total**		707,354	707,354	2.257	2.928	$15,966,255	$20,712,105	$3,249,625
36									
37									
38									

FLORIDA POWER & LIGHT COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

SCHEDULE: E7

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)
Line No.	PURCHASE FROM	Type & Schedule	Total KWH Purchased (000)	KWH For Firm (000)	Fuel Cost (cents/KWH)	Total $ For Fuel Adj (Col(4) * Col(5))
1						
2	**July Estimated**					
3	SJRPP		179,110	179,110	3.703	$6,632,820
4	St Lucie Reliability		45,378	45,378	0.691	$313,583
5	SWA		77,376	77,376	3.552	$2,748,661
6	**Total July Estimated**		301,864	301,864	3.212	$9,695,065
7						
8	**August Estimated**					
9	SJRPP		169,678	169,678	3.672	$6,230,660
10	St Lucie Reliability		45,378	45,378	0.691	$313,583
11	SWA		77,376	77,376	3.552	$2,748,661
12	**Total August Estimated**		292,432	292,432	3.178	$9,292,904
13						
14	**September Estimated**					
15	SJRPP		150,217	150,217	3.615	$5,430,339
16	St Lucie Reliability		43,915	43,915	0.691	$303,468
17	SWA		74,880	74,880	3.552	$2,659,995
18	**Total September Estimated**		269,011	269,011	3.120	$8,393,801
19						
20	**October Estimated**					
21	SJRPP		162,082	162,082	3.587	$5,813,238
22	St Lucie Reliability		45,378	45,378	0.691	$313,583
23	SWA		77,376	77,376	3.552	$2,748,661
24	**Total October Estimated**		284,836	284,836	3.116	$8,875,483
25						
26	**November Estimated**					
27	SJRPP		147,043	147,043	3.479	$5,116,001
28	St Lucie Reliability		44,928	44,928	0.691	$310,467
29	SWA		74,880	74,880	3.552	$2,659,995
30	**Total November Estimated**		266,850	266,850	3.030	$8,086,463
31						
32	**December Estimated**					
33	SJRPP		150,842	150,842	3.451	$5,205,028
34	St Lucie Reliability		46,425	46,425	0.691	$320,816
35	SWA		77,376	77,376	3.552	$2,748,661
36	**Total December Estimated**		274,643	274,643	3.013	$8,274,505
37						
38	**Period Total**					
39	SJRPP		958,970	958,970	3.590	$34,428,085
40	St Lucie Reliability		271,402	271,402	0.691	$1,875,501
41	SWA		459,264	459,264	3.552	$16,314,635
42	**Total Period Total**		1,689,637	1,689,637	3.114	$52,618,221
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FLORIDA POWER & LIGHT COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES

SCHEDULE: E8

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

Line No.	(1) PURCHASE FROM	(2) Type & Schedule	(3) Total KWH Purchased (000)	(4) KWH For Firm (000)	(5) Fuel Cost (cents/KWH)	(6) Total $ For Fuel Adj (Col(4) * Col(5))
1						
2	**July Estimated**					
3	Qualifying Facilities		129,592	129,592	4.395	$5,695,041
4	**Total July Estimated**		129,592	129,592	4.395	$5,695,041
5						
6	**August Estimated**					
7	Qualifying Facilities		128,754	128,754	4.371	$5,627,758
8	**Total August Estimated**		128,754	128,754	4.371	$5,627,758
9						
10	**September Estimated**					
11	Qualifying Facilities		117,249	117,249	4.330	$5,076,456
12	**Total September Estimated**		117,249	117,249	4.330	$5,076,456
13						
14	**October Estimated**					
15	Qualifying Facilities		31,992	31,992	2.566	$820,975
16	**Total October Estimated**		31,992	31,992	2.566	$820,975
17						
18	**November Estimated**					
19	Qualifying Facilities		31,680	31,680	2.452	$776,682
20	**Total November Estimated**		31,680	31,680	2.452	$776,682
21						
22	**December Estimated**					
23	Qualifying Facilities		31,248	31,248	2.356	$736,183
24	**Total December Estimated**		31,248	31,248	2.356	$736,183
25						
26	**Period Total**					
27	Qualifying Facilities		470,515	470,515	3.981	$18,733,095
28	**Total Period Total**		470,515	470,515	3.981	$18,733,095
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FLORIDA POWER & LIGHT COMPANY
ECONOMY ENERGY PURCHASES

SCHEDULE: E9

ESTIMATED FOR THE PERIOD OF: JULY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	PURCHASE FROM	Type & Schedule	Total KWH Purchased (000)	Transaction Cost (cents/KWH)	Total $ for Fuel Adj (Col(3) * Col(4))	Cost if Generated (cents/KWH)	Cost if Generated ($) (Col(3) * Col(6))	Fuel Savings ($) (Col(7) - Col(5))
1								
2	**July Estimated**							
3	Economy	OS	308,600	3.580	$11,047,465	4.546	$14,030,461	$2,982,996
4	Total July Estimated		308,600	3.580	$11,047,465	4.546	$14,030,461	$2,982,996
5								
6	**August Estimated**							
7	Economy	OS	350,400	3.440	$12,055,237	4.486	$15,719,445	$3,664,208
8	Total August Estimated		350,400	3.440	$12,055,237	4.486	$15,719,445	$3,664,208
9								
10	**September Estimated**							
11	Economy	OS	277,000	3.034	$8,404,287	4.201	$11,637,077	$3,232,790
12	Total September Estimated		277,000	3.034	$8,404,287	4.201	$11,637,077	$3,232,790
13								
14	**October Estimated**							
15	Economy	OS	235,900	3.264	$7,699,370	4.582	$10,808,984	$3,109,614
16	Total October Estimated		235,900	3.264	$7,699,370	4.582	$10,808,984	$3,109,614
17								
18	**November Estimated**							
19	Economy	OS	31,800	2.254	$716,733	2.867	$911,633	$194,900
20	Total November Estimated		31,800	2.254	$716,733	2.867	$911,633	$194,900
21								
22	**December Estimated**							
23	Economy	OS	22,500	1.850	$416,295	2.439	$548,795	$132,500
24	Total December Estimated		22,500	1.850	$416,295	2.439	$548,795	$132,500
25								
26	**Period Total**							
27	Economy	OS	1,226,200	3.290	$40,339,389	4.376	$53,656,397	$13,317,008
28	Total Period Total		1,226,200	3.290	$40,339,389	4.376	$53,656,397	$13,317,008
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APPENDIX II

CAPACITY COST RECOVERY

ACTUAL/ESTIMATED TRUE-UP CALCULATION

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 21
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT & SUPPLEMENTAL)*Notice of Adoption of Terry J. Keith's testimony and exhibits by Renae B. Deaton, filed on October 3, 2016, (FPSC DN #07930-16).

TJK-4
DOCKET NO. 160001-EI
FPL WITNESS: TERRY J. KEITH
EXHIBIT _____
PAGES 1-10
AUGUST 4, 2016

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2016 THROUGH DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Total
1	Payments to Non-cogenerators	$5,797,708	$5,882,677	$6,940,701	$6,065,010	$6,320,975	$6,751,736	$6,293,112	$6,293,112	$6,293,112	$6,117,757	$6,117,757	$6,117,757	$74,991,416
2	Payments to Co-generators	$7,865,875	$7,859,530	$7,862,703	$7,153,752	$8,494,181	$7,838,135	$7,875,618	$7,875,618	$7,875,618	$7,875,618	$7,875,618	$7,875,618	$94,327,887
3	Cedar Bay Transaction - Regulatory Asset - Amortization and Return	$9,582,935	$9,552,678	$9,522,421	$9,492,164	$9,461,907	$9,431,637	$9,416,290	$9,385,886	$9,355,482	$9,325,078	$9,294,675	$9,264,271	$113,085,422
4	Cedar Bay Transaction - Regulatory Liability - Amortization and Return	($116,035)	($115,543)	($115,052)	($114,560)	($114,068)	($113,577)	($113,327)	($112,833)	($112,339)	($111,845)	($111,351)	($110,857)	($1,361,389)
5	SJRPP Suspension Accrual	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($9,083,880)
6	Return on SJRPP Suspension Liability	($215,495)	($209,605)	($203,714)	($197,824)	($191,933)	($186,043)	($181,026)	($175,107)	($169,188)	($163,269)	($157,350)	($151,431)	($2,201,987)
7	Incremental Plant Security Costs O&M	$3,384,335	$2,770,804	$3,067,222	$2,869,562	$2,644,814	$2,469,998	$3,778,936	$3,338,845	$3,312,175	$4,246,320	$3,798,490	$6,183,323	$41,864,823
8	Incremental Plant Security Costs Capital	$152,222	$154,484	$157,074	$160,110	$162,740	$165,515	$184,120	$202,339	$205,851	$208,766	$211,897	$215,452	$2,180,571
9	Incremental Nuclear NRC Compliance Costs O&M	$39,528	$284,430	$215,058	$242,810	$287,540	$183,519	$257,467	$269,562	$190,909	$96,443	$90,909	$917,399	$3,075,573
10	Incremental Nuclear NRC Compliance Costs Capital	$599,108	$614,544	$627,540	$674,337	$714,494	$717,277	$728,295	$734,487	$734,212	$733,891	$733,103	$732,634	$8,343,921
11	Transmission of Electricity by Others	$1,846,023	$1,886,685	$1,827,304	$2,218,116	$2,159,231	$6,113	$0	$0	$0	$0	$0	$0	$9,943,472
12	Transmission Revenues from Capacity Sales	($1,085,665)	($637,884)	($991,779)	($894,359)	($517,100)	($384,728)	($241,250)	($230,750)	($259,575)	($207,050)	($229,800)	($327,800)	($6,007,739)
13	Total (Lines 1 through 12)	$27,093,550	$27,285,809	$28,152,487	$26,912,126	$28,665,791	$26,122,593	$27,241,245	$26,824,169	$26,669,266	$27,364,719	$26,866,958	$29,959,376	$329,158,090
14	Jurisdictional Separation Factor [a]	94.67506%	94.67506%	94.67506%	94.67506%	94.67506%	94.67506%	94.67506%	94.67506%	94.67506%	94.67506%	94.67506%	94.67506%	N/A
15	Jurisdictional CCR Charges	$25,650,835	$25,832,856	$26,653,384	$25,479,072	$27,139,355	$24,731,580	$25,790,665	$25,395,798	$25,249,144	$25,907,564	$25,436,309	$28,364,057	$311,630,619
16	Nuclear Cost Recovery Costs	$2,086,094	$3,104,524	$5,127,776	$2,295,622	$2,606,357	$3,156,370	$2,027,702	$2,065,414	$2,962,031	$1,959,644	$1,974,012	$4,884,069	$34,249,614
17	Jurisdictional CCR Charges	$27,736,929	$28,937,381	$31,781,160	$27,774,694	$29,745,711	$27,887,950	$27,818,367	$27,461,212	$28,211,175	$27,867,208	$27,410,320	$33,248,127	$345,880,234
18	CCR Revenues (Net of Revenue Taxes)	$26,963,403	$23,724,517	$25,032,700	$26,889,453	$28,090,196	$31,774,952	$33,232,639	$33,661,147	$32,913,149	$30,353,623	$26,452,278	$26,148,260	345,236,317
19	Prior Period True-up Provision	$395,679	$395,679	$395,679	$395,679	$395,679	$395,679	$395,679	$395,679	$395,679	$395,679	$395,679	$395,679	$4,748,145
20	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$27,359,082	$24,120,196	$25,428,379	$27,285,132	$28,485,875	$32,170,631	$33,628,318	$34,056,826	$33,308,828	$30,749,301	$26,847,957	$26,543,939	$349,984,462
21	True-up Provision for Month - Over/(Under) Recovery (Line 20 - Line 17)	($377,847)	($4,817,185)	($6,352,781)	($489,562)	($1,259,837)	$4,282,681	$5,809,951	$6,595,613	$5,097,654	$2,882,093	($562,363)	($6,704,188)	$4,104,229
22	Interest Provision for Month	$3,433	$2,498	$477	($807)	($1,095)	($814)	$636	$2,476	$4,203	$5,342	$5,586	$4,312	$26,246
23	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	$4,748,145	$3,978,052	($1,232,314)	($7,980,296)	($8,866,344)	($10,522,955)	($6,636,767)	($1,221,859)	$4,980,552	$9,686,729	$12,178,486	$11,226,030	$4,748,145
24	Deferred True-up - Over/(Under) Recovery	$5,938,824	$5,938,824	$5,938,824	$5,938,824	$5,938,824	$5,938,824	$5,938,824	$5,938,824	$5,938,824	$5,938,824	$5,938,824	$5,938,824	$5,938,824
25	Prior Period True-up Provision - Collected/(Refunded) this Month	($395,679)	($395,679)	($395,679)	($395,679)	($395,679)	($395,679)	($395,679)	($395,679)	($395,679)	($395,679)	($395,679)	($395,679)	($4,748,145)
26	End of Period True-up - Over/(Under) Recovery (Sum of Lines 21 through 25)	$9,916,876	$4,706,510	($2,041,472)	($2,927,520)	($4,584,131)	($697,943)	$4,716,965	$10,919,376	$15,625,553	$18,117,310	$17,164,854	$10,069,299	$10,069,299
27														
28	[a] As approved on Order No. PSC-15-0586-FOF-EI.													
29														
30	Totals may not add due to rounding.													
31														
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED VARIANCES
FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2016 THROUGH DECEMBER 2016

Line No.	(1) CCR - Actual Estimated Variance	(2) CCR - 2016 Actual Estimated	(3) CCR - 2016 Original Projection - Supplemental Filing	(4) Dif. CCR - 2016 Original Projection - Supplemental Filing	(5) % Dif. CCR - 2016 Original Projection - Supplemental Filing
1	Payments to Non-cogenerators	$74,991,416	$77,291,599	($2,300,183)	(3.0%)
2	Payments to Co-generators	$94,327,887	$98,812,968	($4,485,081)	(4.5%)
3	Cedar Bay Transaction - Regulatory Asset - Amortization and Return	$113,085,422	$112,998,253	$87,169	0.1%
4	Cedar Bay Transaction - Regulatory Liability - Amortization and Return	($1,361,389)	($1,359,969)	($1,420)	0.1%
5	SJRPP Suspension Accrual	($9,083,880)	($9,083,880)	$0	0.0%
6	Return on SJRPP Suspension Liability	($2,201,987)	($2,197,172)	($4,814)	0.2%
7	Incremental Plant Security Costs O&M	$41,864,823	$44,411,965	($2,547,142)	(5.7%)
8	Incremental Plant Security Costs Capital	$2,180,571	$2,256,096	($75,525)	(3.3%)
9	Incremental Nuclear NRC Compliance Costs O&M	$3,075,573	$2,219,642	$855,931	38.56%
10	Incremental Nuclear NRC Compliance Costs Capital	$8,343,921	$8,005,830	$338,091	4.22%
11	Transmission of Electricity by Others	$9,943,472	$10,314,030	($370,558)	(3.6%)
12	Transmission Revenues from Capacity Sales	($6,007,739)	($4,458,150)	($1,549,589)	34.8%
13	Total (Lines 1 through 12)	$329,158,090	$339,211,211	($10,053,121)	(3.0%)
14	Jurisdictional Separation Factor [(a)]	94.67506%	94.67506%	(0.00000%)	(0.0%)
15	Jurisdictional CCR Charges	$311,630,619	$321,148,426	($9,517,807)	(3.0%)
16	Nuclear Cost Recovery Costs	$34,249,614	$34,249,614	$0	0.0%
17	Jurisdictional CCR Charges	$345,880,234	$355,398,040	($9,517,807)	(2.7%)
18	CCR Revenues (Net of Revenue Taxes)	$345,236,317	$350,649,896	($5,413,578)	(1.5%)
19	Prior Period True-up Provision	$4,748,145	$4,748,145	$0	0.0%
20	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$349,984,462	$355,398,040	($5,413,578)	(1.5%)
21	True-up Provision for Month - Over/(Under) Recovery (Line 20 - Line 17)	$4,104,229	$0	$4,104,229	0.0%
22	Interest Provision for Month	$26,246	$0	$26,246	N/A
23	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	$4,748,145	$4,748,145	$0	0.0%
24	Deferred True-up - Over/(Under) Recovery	$5,938,824	$0	$5,938,824	N/A
25	Prior Period True-up Provision - Collected/(Refunded) this Month	($4,748,145)	($4,748,145)	($0)	0.0%
26	End of Period True-up - Over/(Under) Recovery (Sum of Lines 21 through 25)	$10,069,299	$0	$10,069,299	N/A
27					
28	[(a)] As approved on Order No. PSC-15-0586-FOF-EI.				
29					
30	Totals may not add due to rounding.				
31					
32					
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Florida Power & Light Company
Capacity Cost Recovery Clause
For the Period January through June 2016

Return on Capital Investments, Depreciation and Taxes
Incremental Security
(in Dollars)

Line		Beginning of Period Amount	Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$212,241	$392,463	$354,184	$353,875	($76,791)	$449,511	$1,685,484
	b. Clearings to Plant		$7,569	$6,067	$2,001	$49,227	$319,244	$860	$384,967
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other		$0	$0	$0	$0	$0	$0	$0
2.	Plant-In-Service/Depreciation Base	$4,210,542	$4,218,111	$4,224,178	$4,226,178	$4,275,405	$4,594,649	$4,595,509	n/a
3.	Less: Accumulated Depreciation	$105,341	$125,539	$145,751	$165,772	$186,033	$206,571	$227,349	n/a
4.	CWIP - Non Interest Bearing	$12,761,654	$12,973,895	$13,366,358	$13,720,543	$14,074,418	$13,997,627	$14,447,138	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$16,866,855	$17,066,467	$17,444,785	$17,780,949	$18,163,790	$18,385,705	$18,815,298	n/a
6.	Average Net Investment		$16,966,661	$17,255,626	$17,612,867	$17,972,369	$18,274,748	$18,600,501	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (a)		$110,951	$112,841	$115,177	$117,528	$119,505	$121,635	$697,637
	b. Debt Component (Line 6 x debt rate x 1/12) (b)		$21,073	$21,431	$21,875	$22,322	$22,697	$23,102	$132,500
8.	Investment Expenses								
	a. Depreciation		$20,198	$20,212	$20,022	$20,261	$20,538	$20,778	$122,009
	b. Amortization		$0	$0	$0	$0	$0	$0	$0
	c. Other								
9.	Total System Recoverable Expenses (Lines 11 & 12)		$152,222	$154,484	$157,074	$160,110	$162,740	$165,515	$952,145

Notes:

(a) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component is 4.8201%, which is based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(b) The Debt Component is 1.4904%, which is based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

Totals may not add due to rounding.

Florida Power & Light Company
Capacity Cost Recovery Clause
For the Period July through December 2016

Return on Capital Investments, Depreciation and Taxes
Incremental Security
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		($12,255,158)	$162,588	$403,214	$399,822	$484,442	$232,951	($8,886,658)
	b. Clearings to Plant		$13,199,847	$330,883	$25,980	$4,020	$4,406	$235,074	$14,185,178
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other		$0	$0	$0	$0	$0	$0	$0
2.	Plant-In-Service/Depreciation Base	$4,595,509	$17,795,357	$18,126,240	$18,152,220	$18,156,240	$18,160,646	$18,395,720	n/a
3.	Less: Accumulated Depreciation	$227,349	$260,789	$307,136	$353,751	$400,389	$447,033	$493,856	n/a
4.	CWIP - Non Interest Bearing	$14,447,138	$2,191,980	$2,354,568	$2,757,782	$3,157,604	$3,642,046	$3,874,996	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$18,815,298	$19,726,548	$20,173,672	$20,556,251	$20,913,455	$21,355,658	$21,776,859	n/a
6.	Average Net Investment		$19,270,923	$19,950,110	$20,364,961	$20,734,853	$21,134,557	$21,566,259	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (a)		$128,310	$132,832	$135,594	$138,057	$140,718	$143,592	$1,516,740
	b. Debt Component (Line 6 x debt rate x 1/12) (b)		$22,372	$23,160	$23,642	$24,071	$24,535	$25,036	$275,316
8.	Investment Expenses								
	a. Depreciation		$33,439	$46,347	$46,615	$46,638	$46,644	$46,824	$388,515
	b. Amortization		$0	$0	$0	$0	$0	$0	$0
	c. Other								
9.	Total System Recoverable Expenses (Lines 11 & 12)		$184,120	$202,339	$205,851	$208,766	$211,897	$215,452	$2,180,571

Notes:

(a) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component is 4.9078%, which is based on the May 2016 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(b) The Debt Component is 1.3931%, which is based on the May 2016 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

Totals may not add due to rounding.

Florida Power & Light Company
Capacity Cost Recovery Clause
For the Period January through June 2016

Return on Capital Investments, Depreciation and Taxes
Incremental Nuclear NRC Compliance
(in Dollars)

Line		Beginning of Period Amount	Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$1,703,761	$1,304,227	$1,592,068	($15,688,836)	$0	$0	($11,088,779)
	b. Clearings to Plant		$709,947	$263,841	$316,247	$19,570,169	$360,577	$505,897	$21,726,678
	c. Clearings to Plant - Base		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other		$0	$0	$0	$0	$0	($2,961)	($2,961)
2.	Incremental Plant-In-Service/Depreciation (a)	$52,069,931	$52,779,878	$53,043,719	$53,359,966	$72,930,135	$73,290,712	$73,796,609	
3.	Less: Accumulated Depreciation	$554,156	$657,122	$760,835	$864,827	$993,997	$1,147,922	$1,299,486	
4.	CWIP - Non Interest Bearing	$11,089,331	$12,793,092	$14,097,320	$15,689,388	$552	$552	$552	
5.	Net Investment (Lines 2 - 3 + 4)	$62,605,106	$64,915,849	$66,380,204	$68,184,528	$71,936,691	$72,143,343	$72,497,675	n/a
6.	Total Estimated Capital Expenditures Included in Base Rates (b)		$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	
7.	Base Rate Capital Expenditures Closed to Plant-in-Service (c)		$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	
8.	Remaining Amount Included in Base Rates (Lines 6 - 7)		$0	$0	$0	$0	$0	$0	
9.	Adjusted Net Investment (Lines 5 - 8)	$62,605,106	$64,915,849	$66,380,204	$68,184,528	$71,936,691	$72,143,343	$72,497,675	
10.	Average Net Investment		$63,760,477	$65,648,027	$67,282,366	$70,060,609	$72,040,017	$72,320,509	n/a
11.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (d)		$416,953	$429,296	$439,983	$458,151	$471,095	$472,930	$2,688,408
	b. Debt Component (Line 6 x debt rate x 1/12) (e)		$79,191	$81,535	$83,565	$87,015	$89,474	$89,822	$510,601
12.	Investment Expenses								
	a. Depreciation		$102,965	$103,714	$103,991	$129,170	$153,925	$154,525	$748,291
	b. Amortization		$0	$0	$0	$0	$0	$0	$0
	c. Other								$0
13.	Total System Recoverable Expenses (Lines 11 & 12)		$599,108	$614,544	$627,540	$674,337	$714,494	$717,277	$3,947,300

Notes:

[a] Represents nuclear NRC compliance plant-in-service in excess of the total estimated capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI) on line 6.

[b] Represents forecasted nuclear NRC compliance capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI).

[c] Represents base rate recoverable nuclear NRC compliance capital expenditures closed to plant-in-service.

[d] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component is 4.8201%, which is based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[e] The Debt Component is 1.4904%, which is based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

Totals may not add due to rounding.

Florida Power & Light Company
Capacity Cost Recovery Clause
For the Period June through December 2016

Return on Capital Investments, Depreciation and Taxes
Incremental Nuclear NRC Compliance
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$1,013,010	$20,000	$30,000	$30,000	$40,000	$55,965	($9,899,804)
	b. Clearings to Plant		$673,875	$48,537	$111,103	$30,308	$3,555	$77,332	$22,671,388
	c. Clearings to Plant - Base		$0	$0	$0	$0	$0	$0	$0
	d. Retirements		$0	$0	$0	$0	$0	$0	$0
	e. Other		$0	$0	$0	$0	$0	$0	($2,961)
2.	Incremental Plant-In-Service/Depreciation Base (a)	$73,796,609	$74,470,484	$74,519,021	$74,630,124	$74,660,432	$74,663,987	$74,741,319	n/a
3.	Less: Accumulated Depreciation	$1,299,486	$1,454,927	$1,610,914	$1,767,027	$1,923,253	$2,079,506	$2,235,821	n/a
4.	CWIP - Non Interest Bearing	$552	$1,013,562	$1,033,562	$1,063,562	$1,093,562	$1,133,562	$1,189,527	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$72,497,675	$74,029,120	$73,941,670	$73,926,659	$73,830,742	$73,718,043	$73,695,026	n/a
6.	Total Estimated Capital Expenditures Included in Base Rates (b)	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	
7.	Base Rate Capital Expenditures Closed to Plant-in-Service (c)	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	
8.	Remaining Amount Included in Base Rates (Lines 6 - 7)	$0	$0	$0	$0	$0	$0	$0	
9.	Adjusted Net Investment (Lines 5 - 8)	$72,497,675	$74,029,120	$73,941,670	$73,926,659	$73,830,742	$73,718,043	$73,695,026	
10.	Average Net Investment		$73,263,398	$73,985,395	$73,934,164	$73,878,701	$73,774,392	$73,706,534	n/a
11.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (d)		$487,802	$492,610	$492,269	$491,899	$491,205	$490,753	$5,634,946
	b. Debt Component (Line 6 x debt rate x 1/12) (e)		$85,051	$85,890	$85,830	$85,766	$85,645	$85,566	$1,024,349
12.	Investment Expenses								
	a. Depreciation		$155,441	$155,987	$156,113	$156,226	$156,254	$156,315	$1,684,626
	b. Amortization		$0	$0	$0	$0	$0	$0	$0
	c. Other								
13.	Total System Recoverable Expenses (Lines 11 & 12)		$728,295	$734,487	$734,212	$733,891	$733,103	$732,634	$8,343,921

Notes:

(a) Represents nuclear NRC compliance plant-in-service in excess of the total estimated capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI) on line 6.

(b) Represents forecasted nuclear NRC compliance capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI).

(c) Represents base rate recoverable nuclear NRC compliance capital expenditures closed to plant-in-service.

(d) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component is 4.9078%, which is based on the May 2016 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(e) The Debt Component is 1.3931%, which is based on the May 2016 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY

CEDAR BAY TRANSACTION
Regulatory Asset Related to the Loss of the PPA and Income Tax Gross-Up (Amortization and Return Calculation)
For the Period January through December 2016

Line No.	Description	Beginning of Period	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Estimated Total
1	Regulatory Asset - Loss of PPA		$419,946,428	$416,058,035	$412,169,642	$408,281,249	$404,392,856	$400,504,463	$396,616,124	$392,727,731	$388,839,338	$384,950,945	$381,062,552	$377,174,159	n/a
2	Regulatory Asset - Loss of PPA Amort		$3,888,393	$3,888,393	$3,888,393	$3,888,393	$3,888,393	$3,888,339	$3,888,393	$3,888,393	$3,888,393	$3,888,393	$3,888,393	$3,888,393	$46,660,662
3	Unamortized Regulatory Asset - Loss of PPA	$419,946,428	$416,058,035	$412,169,642	$408,281,249	$404,392,856	$400,504,463	$396,616,124	$392,727,731	$388,839,338	$384,950,945	$381,062,552	$377,174,159	$373,285,766	n/a
4	Average Unamortized Regulatory Asset - Loss of PPA		$418,002,232	$414,113,839	$410,225,446	$406,337,053	$402,448,660	$398,560,293	$394,671,927	$390,783,534	$386,895,141	$383,006,748	$379,118,355	$375,229,962	n/a
5	Regulatory Asset - Income Tax Gross Up		$263,727,041	$261,285,124	$258,843,207	$256,401,290	$253,959,373	$251,517,416	$249,075,499	$246,633,582	$244,191,665	$241,749,748	$239,307,831	$236,865,914	
6	Regulatory Asset Amortization - Income Tax Gross-Up		$2,441,917	$2,441,917	$2,441,917	$2,441,917	$2,441,917	$2,441,957	$2,441,917	$2,441,917	$2,441,917	$2,441,917	$2,441,917	$2,441,917	$29,303,044
7	Unamortized Regulatory Asset - Income Tax Gross Up		$261,285,124	$258,843,207	$256,401,290	$253,959,373	$251,517,456	$249,075,459	$246,633,582	$244,191,665	$241,749,748	$239,307,831	$236,865,914	$234,423,997	
8	Return on Unamortized Regulatory Asset - Loss of PPA only														
	a. Equity Component [(a)]		$1,679,031	$1,663,412	$1,647,794	$1,632,175	$1,616,556	$1,600,937	$1,614,129	$1,598,226	$1,582,324	$1,566,421	$1,550,518	$1,534,615	$19,286,139
	b. Equity Comp. grossed up for taxes (Line 8a / 0.61425) [(b)]		$2,733,466	$2,708,038	$2,682,611	$2,657,183	$2,631,755	$2,606,328	$2,627,805	$2,601,915	$2,576,026	$2,550,136	$2,524,246	$2,498,357	$31,397,866
	c. Debt Component (Line 4 * 1.4904% / 12)		$519,159	$514,329	$509,500	$504,671	$499,841	$495,012	$458,175	$453,661	$449,147	$444,633	$440,118	$435,604	$5,723,849
9	Total Return Requirements (Line 8b + 8c)		$3,252,625	$3,222,368	$3,192,111	$3,161,854	$3,131,597	$3,101,340	$3,085,980	$3,055,576	$3,025,172	$2,994,768	$2,964,365	$2,933,961	$37,121,715
10	Total Recoverable Expenses (Line 2 + 6 + 9)		$9,582,935	$9,552,678	$9,522,421	$9,492,164	$9,461,907	$9,431,637	$9,416,290	$9,385,886	$9,355,482	$9,325,078	$9,294,675	$9,264,271	$113,085,422

[(a)] The monthly Equity Component for the Jan. - Jun. 2016 actual period is 4.8201%, reflects a 10.5% return on equity. Monthly Equity Component for the Jul. - Dec. 2016 estimated period is 4.9078% based on the May 2016 ROR Earnings Surveillance Report, reflects a 10.5% return on equity, consistent with FPSC Order No. PSC-12-0425-PAA-EU.

[(b)] Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35%.

[(c)] The Debt Component for the Jan. - Jun. 2016 actual period is 1.4904%. Debt Component for the Jul. - Dec. 2016 estimated period is 1.3931% based on the May 2016 ROR Earnings Surveillance Report, reflects a 10.5% ROE, consistent with FPSC Order No. PSC-12-0425-PAA-EU.

[(d)] Recovery of the Cedar Bay Transaction is based on the settlement agreement approved by the FPSC in Docket No. 150075-EI at the special agenda on August 27, 2015.

TOTAL MAY NOT ADD DUE TO ROUNDING

FLORIDA POWER & LIGHT COMPANY

CEDAR BAY TRANSACTION

Regulatory Liability - Book/Tax Timing Difference Associated to Plant Asset - Amortization and Return Calculation

For the Period January through December 2016

Line No.	Description	Beginning of Period	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Estimated Total
1	Regulatory Liability - Book/Tax Timing Difference		($6,823,733)	($6,760,550)	($6,697,367)	($6,634,184)	($6,571,001)	($6,507,818)	($6,444,635)	($6,381,452)	($6,318,269)	($6,255,086)	($6,191,903)	($6,128,720)	n/a
2	Regulatory Liability Amortization		$63,183	$63,183	$63,183	$63,183	$63,183	$63,183	$63,183	$63,183	$63,183	$63,183	$63,183	$63,183	$758,196
3	Unamortized Regulatory Liability - Book/Tax Timing Diff	($6,823,733)	($6,760,550)	($6,697,367)	($6,634,184)	($6,571,001)	($6,507,818)	($6,444,635)	($6,381,452)	($6,318,269)	($6,255,086)	($6,191,903)	($6,128,720)	($6,065,537)	n/a
4	Average Unamortized Regulatory Liability - Book/Tax Timing Difference		($6,792,142)	($6,728,959)	($6,665,776)	($6,602,593)	($6,539,410)	($6,476,227)	($6,413,044)	($6,349,861)	($6,286,678)	($6,223,495)	($6,160,312)	($6,097,129)	n/a
5	Return on Unamortized Regulatory Liability - Book/Tax Timing Difference														
	a. Equity Component [(a)]		($27,283)	($27,029)	($26,775)	($26,521)	($26,268)	($26,014)	($26,228)	($25,970)	($25,711)	($25,453)	($25,194)	($24,936)	($313,381)
	b. Equity Comp. grossed up for taxes (Line 5a / 0.61425) [(b)]		($44,416)	($44,003)	($43,590)	($43,177)	($42,764)	($42,350)	($42,699)	($42,279)	($41,858)	($41,437)	($41,017)	($40,596)	($510,186)
	c. Debt Component (Line 4 * 1.4904% / 12)		($8,436)	($8,357)	($8,279)	($8,200)	($8,122)	($8,043)	($7,445)	($7,372)	($7,298)	($7,225)	($7,152)	($7,078)	($93,007)
6	Total Return Requirements (Line 5b + 5c)		($52,852)	($52,360)	($51,869)	($51,377)	($50,885)	($50,394)	($50,144)	($49,650)	($49,156)	($48,662)	($48,168)	($47,674)	($603,193)
7	Total Recoverable Expenses (Line 2 + 6)		($116,035)	($115,543)	($115,052)	($114,560)	($114,068)	($113,577)	($113,327)	($112,833)	($112,339)	($111,845)	($111,351)	($110,857)	($1,361,389)

[(a)] The monthly Equity Component for the Jan. - Jun. 2016 actual period is 4.8201%, reflects a 10.5% return on equity. Monthly Equity Component for the Jul. - Dec. 2016 estimated period is 4.9078% based on the May 2016 ROR Earnings Surveillance Report, reflects a 10.5% return on equity, consistent with FPSC Order No. PSC-12-0425-PAA-EU.

[(b)] Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35%.

[(c)] The Debt Component for the Jan. - Jun. 2016 actual period is 1.4904%. Debt Component for the Jul. - Dec. 2016 estimated period is 1.3931% based on the May 2016 ROR Earnings Surveillance Report, reflects a 10.5% ROE, consistent with FPSC Order No. PSC-12-

[(d)] Recovery of the Cedar Bay Transaction is based on the settlement agreement approved by the FPSC in Docket No. 150075-EI at the special agenda on August 27, 2015.

TOTAL MAY NOT ADD DUE TO ROUNDING

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.50%

CAPITAL STRUCTURE AND COST RATES PER MAY 2015 EARNINGS SURVEILLANCE REPORT

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	7,868,539,536	29.834%	4.80%	1.43%	1.43%
SHORT_TERM_DEBT	346,840,443	1.315%	2.03%	0.03%	0.03%
PREFERRED_STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER_DEPOSITS	421,524,845	1.598%	2.04%	0.03%	0.03%
COMMON_EQUITY	12,106,290,409	45.901%	10.50%	4.82%	7.85%
DEFERRED_INCOME_TAX	5,629,438,935	21.344%	0.00%	0.00%	0.00%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	2,138,560	0.008%	8.25%	0.00%	0.00%
TOTAL	$26,374,772,728	100.00%		6.31%	9.34%

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	$7,868,539,536	39.39%	4.796%	1.889%	1.889%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	12,106,290,409	60.61%	10.500%	6.364%	10.360%
TOTAL	$19,974,829,945	100.00%		8.253%	12.250%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	1.4309%
SHORT TERM DEBT	0.0267%
CUSTOMER DEPOSITS	0.0326%
TAX CREDITS -WEIGHTED	0.0002%
TOTAL DEBT	**1.4904%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.8196%
TAX CREDITS -WEIGHTED	0.0005%
TOTAL EQUITY	**4.8201%**
TOTAL	6.3105%
PRE-TAX EQUITY	7.8472%
PRE-TAX TOTAL	9.3375%

Note:

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

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.50%

CAPITAL STRUCTURE AND COST RATES PER MAY 2016 EARNINGS SURVEILLANCE REPORT

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	8,001,609,073	28.728%	4.638%	1.33%	1.33%
SHORT_TERM_DEBT	439,350,198	1.577%	1.857%	0.03%	0.03%
PREFERRED_STOCK	0	0.000%	0.000%	0.00%	0.00%
CUSTOMER_DEPOSITS	418,988,300	1.504%	2.074%	0.03%	0.03%
COMMON_EQUITY	13,017,322,068	46.735%	10.500%	4.91%	7.99%
DEFERRED_INCOME_TAX	5,973,525,955	21.446%	0.000%	0.00%	0.00%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.000%	0.00%	0.00%
WEIGHTED COST	2,534,605	0.009%	8.269%	0.00%	0.00%
TOTAL	$27,853,330,199	100.00%		6.30%	9.38%

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	$8,001,609,073	38.07%	4.638%	1.766%	1.766%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	13,017,322,068	61.93%	10.500%	6.503%	10.587%
TOTAL	$21,018,931,141	100.00%		8.269%	12.352%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	1.3325%
SHORT TERM DEBT	0.0293%
CUSTOMER DEPOSITS	0.0312%
TAX CREDITS -WEIGHTED	0.0002%
TOTAL DEBT	**1.3931%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.9072%
TAX CREDITS -WEIGHTED	0.0006%
TOTAL EQUITY	**4.9078%**
TOTAL	6.3009%
PRE-TAX EQUITY	7.9899%
PRE-TAX TOTAL	9.3830%

Note:

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

APPENDIX II
FUEL COST RECOVERY
2017 E-SCHEDULES

FOR THE PERIOD JANUARY 2017 THROUGH DECEMBER 2017

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 22
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT & SUPPLEMENTAL)*Notice of Adoption of Terry J. Keith's testimony and exhibits by Renae B. Deaton, filed on October 3, 2016, (FPSC DN #07930-16).
DESCRIPTION: *R. B. Deaton TJK-5

TJK-5
DOCKET NO. 160001-EI
FPL WITNESS: TERRY J. KEITH
EXHIBIT _____
PAGES 1-92
SEPTEMBER 2, 2016

APPENDIX II
FUEL COST RECOVERY
2017 E SCHEDULES - JAN 2017 THROUGH DEC 2017
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FLORIDA POWER & LIGHT COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

SCHEDULE: E1

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)
Line No.		Dollars	MWH	Cents/KWH
1	Fuel Cost of System Net Generation (E3)	$3,009,808,353	116,063,908	2.5932
2	Cedar Bay – Rail Coal Cars Lease per Docket No. 150075-EI	$720,000		
3	TOTAL COST OF GENERATED POWER	$3,010,528,353	116,063,908	2.5939
4	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	$105,254,087	3,238,162	3.2504
5	Energy Cost of Economy Purchases (E9)	$36,493,143	1,332,100	2.7395
6	Payments to Qualifying Facilities (E8)	$45,826,252	1,066,468	4.2970
7	TOTAL COST OF PURCHASED POWER	$187,573,481	5,636,730	3.3277
8	TOTAL AVAILABLE MWH (LINE 3 + LINE 7)		121,700,638	
9	Fuel Cost of Economy Sales (E6)	($55,389,097)	(2,095,700)	2.6430
10	Gain from Off-System Sales (E6)	($12,443,512)	N/A	N/A
11	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	($4,235,814)	(614,604)	0.6892
12	TOTAL FUEL COST AND GAINS OF POWER SALES	($72,068,422)	(2,710,304)	2.6591
13	Incremental Personnel, Software, and Hardware Costs	$476,708	N/A	N/A
14	Variable Power Plant O&M Costs over 514,000 MW Threshold	$496,340	N/A	N/A
15	TOTAL INCREMENTAL OPTIMIZATION COSTS	973,048	N/A	N/A
16	Dodd Frank Fees	$4,500	N/A	N/A
17	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 3 + 7 + 12 + 15 + 16)	$3,127,010,961	118,990,334	2.6280
18	Net Unbilled Sales [1]	($63,715,119)	(2,424,514)	(0.0562)
19	Company Use [1]	$9,381,033	356,971	0.0083
20	T & D Losses [1]	$203,255,712	7,734,372	0.1794
21	SYSTEM MWH SALES	$3,127,010,961	113,323,506	2.7594
22	Wholesale MWH Sales	$165,217,500	5,987,512	2.7594
23	Jurisdictional MWH Sales	$2,961,793,460	107,335,994	2.7594
24	Jurisdictional Loss Multiplier	$4,531,544		1.00153
25	Jurisdictional MWH Sales Adjusted for Line Losses	$2,966,325,004	107,335,994	2.7636
26	NET TRUE-UP (OVER)/UNDER RECOVERY (E1-A)	$26,483,684	107,335,994	0.0247
27	TOTAL JURISDICTIONAL FUEL COST	$2,992,808,688	107,335,994	2.7883
28	Revenue Tax Factor	$2,154,822		1.00072
29	Fuel Factor Adjusted for Taxes	$2,994,963,511	107,335,994	2.7903
30	GPIF [2]	$31,658,059	107,335,994	0.0295
31	Jurisdictionalized Incentive Mechanism - FPL Portion	$500,861	107,335,994	0.0005
32	Vendor Settlement Refund	($7,573,924)	107,335,994	(0.0071)
33	Fuel Factor including GPIF (Line 29 + 30 + 31 + 32)	$3,019,548,507	107,335,994	2.8132
34	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			2.813
35				
36	[1] For Informational Purposes Only			
37	[2] Calculation Based on Jurisdictional KWH Sales			
38				
39	Note: Totals may not add due to rounding.			
40				

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

SCHEDULE: E1-A

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

Line No.		Annual Total
1	Actual/Estimated over/(under) recovery [1]	($26,483,684)
2	Final over/(under) recovery	$0
3	Total over/(under) recovery to be included in projected period [2]	($26,483,684)
4		
5	Total Jurisdictional Sales (MWH)	107,335,994
6		
7	True-Up Factor (cents/kWh)	(0.0247)
8		
9	[1] Actual/Estimated over/(under) recovery for January 2016 - December 2016	
10	[2] Projected Period January 2017 - December 2017 (Schedule E1, Line 26)	
11		
12	Note: Totals may not add due to rounding.	
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FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT

REVISED - SCHEDULE: E1-B

FOR THE PERIOD OF: JANUARY 2016 THROUGH DECEMBER 2016

Line No.	(1)	(2) January Actual	(3) February Actual	(4) March Actual	(5) April Actual	(6) May Actual	(7) June Actual	(8) July Actual	(9) August Estimated	(10) September Estimated	(11) October Estimated	(12) November Estimated	(13) December Estimated	(14) 12 Month Period
1	**Fuel Costs & Net Power Transactions**													
2	Fuel Cost of System Net Generation (Per A3) [1]	$201,632,120	$185,554,216	$191,236,901	$218,364,742	$229,257,708	$252,425,555	$321,585,323	$277,561,133	$254,146,222	$247,448,493	$202,033,361	$210,377,139	$2,791,622,914
3	Cedar Bay – Rail Coal Cars Lease per Docket No. 150075-EI	$137,532	$271,278	$147,241	$144,435	$130,857	$131,751	$130,514	$120,000	$120,000	$120,000	$120,000	$120,000	$1,693,606
4	Fuel Cost of Power Sold (Per A6)	($10,675,105)	($6,757,682)	($2,453,228)	($4,786,732)	($2,412,798)	($2,003,416)	($1,342,884)	($3,010,994)	($2,575,173)	($1,765,432)	($2,395,112)	($2,923,429)	($43,101,986)
5	Gains from Off-System Sales (Per A6)	($3,997,835)	($2,907,354)	($793,597)	($3,079,923)	($951,874)	($601,482)	($250,631)	($636,800)	($690,175)	($347,950)	($366,200)	($547,200)	($15,171,021)
6	Fuel Cost of Purchased Power (Per A7)	$2,411,393	$5,384,645	$6,690,344	$6,408,911	$6,721,506	$7,054,568	$15,249,302	$9,292,904	$8,393,801	$8,875,483	$8,086,463	$8,274,505	$92,843,826
7	Energy Payments to Qualifying Facilities (Per A8)	$386,643	$317,765	$1,801,911	$3,858,818	$4,895,544	$3,134,762	$6,129,011	$5,627,758	$5,076,456	$820,975	$776,682	$736,183	$33,562,507
8	Energy Cost of Economy Purchases (Per A9)	$145,200	$9,812	$664,006	$6,285,624	$6,470,979	$7,168,322	$17,918,539	$12,055,237	$8,404,287	$7,699,370	$716,733	$416,295	$67,954,405
9	Total Fuel Costs & Net Power Transactions	$190,039,948	$181,872,680	$197,293,578	$227,195,875	$244,111,921	$267,310,058	$359,419,174	$301,009,240	$272,875,418	$262,850,938	$208,971,929	$216,453,493	$2,929,404,251
10														
11	**Incremental Optimization Costs**													
12	Incremental Personnel, Software, and Hardware Costs (Per A2)	$39,910	$36,980	$41,605	$39,413	$40,308	$41,454	$38,202	$41,180	$39,704	$38,227	$39,704	$39,704	$476,389
13	Variable Power Plant O&M Costs over 514,000 MWH Threshold (Per A6)	$1,317	$589,232	$270,672	$518,520	$201,262	$119,589	$50,835	$88,672	$99,280	$89,760	$101,320	$146,880	$2,277,340
14	Total	$41,226	626,213	312,277	557,934	241,570	161,043	89,037	129,852	138,984	127,987	141,024	186,584	2,753,729
15														
16	Dodd Frank Fees	$375	$0	$750	$0	$750	$375	$375	$375	$375	$375	$375	$375	$4,500
17														
18	**Adjustments to Fuel Cost**													
19	Energy Imbalance Fuel Revenues	($548)	$7,315	$6,763	$20,705	$8,753	$14,117	$41,251	$0	$0	$0	$0	$0	$98,356
20	Inventory Adjustments	($677,969)	$91,469	($178,709)	$82,937	($157,064)	$120,075	($70,011)	$0	$0	$0	$0	$0	($789,272)
21	Non Recoverable Oil/Tank Bottoms	$0	$0	($80,208)	$0	$0	$230,772	$0	$0	$0	$0	$0	$0	$150,564
22	Gas Reserves Refund [5]	$0	$0	$0	$0	$0	($21,294,315)	$0	$0	$0	$0	$0	$0	($21,294,315)
23	Variable Power Plant O&M Correction [6]	$0	$0	$0	$0	$0	($832,856)	$0	$0	$0	$0	$0	$0	($832,856)
24	Adjusted Total Fuel Costs & Net Power Transactions	$189,403,032	$182,597,676	$197,354,451	$227,857,451	$244,205,930	$245,709,269	$359,479,826	$301,139,467	$273,014,776	$262,979,300	$209,113,327	$216,640,452	$2,909,494,958
25	**Jurisdictional kWh Sales**													
26	Jurisdictional kWh Sales	8,477,060,498	7,108,751,712	7,791,736,459	8,414,360,754	8,721,865,851	10,084,259,719	11,403,351,282	10,493,894,259	10,260,705,262	9,462,770,364	8,246,522,500	8,151,744,737	108,617,023,397
27	Sales for Resale	504,756,935	509,624,758	435,645,390	536,378,082	517,499,753	594,973,322	641,503,285	648,939,796	625,840,767	594,452,738	540,505,365	443,461,630	6,593,581,822
28	Sub-Total Sales	8,981,817,433	7,618,376,470	8,227,381,849	8,950,738,836	9,239,365,604	10,679,233,041	12,044,854,567	11,142,834,055	10,886,546,029	10,057,223,102	8,787,027,865	8,595,206,367	115,210,605,219
29														
30	**Jurisdictional % of Total Sales (Line 26/28)**	94.38024%	93.31059%	94.70493%	94.00744%	94.39897%	94.42869%	94.67405%	94.17617%	94.25125%	94.08930%	93.84883%	94.84059%	94.27693%
31	**True-up Calculation**													
32	Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$242,137,682	$200,663,968	$220,698,604	$206,705,034	$216,009,593	$253,879,070	$291,723,278	$261,634,149	$255,820,273	$235,926,131	$205,602,596	$203,239,593	$2,794,039,971
33	**Fuel Adjustment Revenues Not Applicable to Period**													
34	Prior Period True-up (Collected)/Refunded This Period [2]	($5,568,187)	($5,568,187)	($5,568,187)	($5,568,187)	($5,568,187)	($5,568,187)	($5,568,187)	($5,568,187)	($5,568,187)	($5,568,187)	($5,568,187)	($5,568,187)	($66,818,243)
35	GPIF, Net of Revenue Taxes [3]	($1,940,528)	($1,940,528)	($1,940,528)	($1,940,528)	($1,940,528)	($1,940,528)	($1,940,528)	($1,940,528)	($1,940,528)	($1,940,528)	($1,940,528)	($1,940,528)	($23,286,336)
36	Incentive Mechanism Collection	($1,028,392)	($1,028,392)	($1,028,392)	($1,028,392)	($1,028,392)	($1,028,392)	($1,028,392)	($1,028,392)	($1,028,392)	($1,028,392)	($1,028,392)	($1,028,392)	($12,340,708)
37	Midcourse correction - Prior Period True-up (Collected)/Refunded This Period	$0	$0	$0	$3,307,472	$3,307,472	$3,307,472	$3,307,472	$3,307,472	$3,307,472	$3,307,472	$3,307,472	$3,307,472	$29,767,250
38	Jurisdictional Fuel Revenues Applicable to Period	$233,600,575	$192,126,861	$212,161,496	$201,475,399	$210,779,958	$248,649,435	$286,493,643	$256,404,514	$250,590,638	$230,696,496	$200,372,961	$198,009,958	$2,721,361,934
39	Adjusted Total Fuel Costs & Net Power Transactions	$189,403,032	$182,597,676	$197,354,451	$227,857,451	$244,205,930	$245,709,269	$359,479,826	$301,139,467	$273,014,776	$262,979,300	$209,113,327	$216,640,452	$2,909,494,958
40	Jurisdictional Sales % of Total kWh Sales (Line 30)	94.38024%	93.31059%	94.70493%	94.00744%	94.39897%	94.42869%	94.67405%	94.17617%	94.25125%	94.08930%	93.84883%	94.84059%	94.27693%
41	Juris. Total Fuel Costs & Net Power Trans. (Line 39xLine40x1.00168)	$179,104,042	$170,711,808	$187,265,120	$214,562,817	$230,915,170	$232,409,838	$340,905,871	$284,078,067	$257,752,137	$247,851,074	$196,580,112	$205,808,261	$2,747,944,316
42	True-up Provision for the Month - Over/(Under) Recovery (Line 38 - Line 41)	$54,496,533	$21,415,052	$24,896,376	($13,087,418)	($20,135,212)	$16,239,597	($54,412,229)	($27,673,552)	($7,161,499)	($17,154,578)	$3,792,849	($7,798,303)	($26,582,383)
43	Interest Provision for the Month	($2,339)	$12,473	$23,375	$24,402	$17,722	$18,833	$16,222	$4,689	($740)	($4,286)	($5,872)	($5,781)	$98,698
44	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	($66,818,243)	($6,755,862)	$20,239,850	$50,727,789	$39,925,486	$22,068,711	$40,587,856	($11,547,436)	($36,955,584)	($41,857,108)	($56,755,257)	($50,707,565)	($66,818,243)
45	Deferred True-up Beginning of Period - Over/(Under) Recovery [4]	$29,767,250	$29,767,250	$29,767,250	$29,767,250	$29,767,250	$29,767,250	$29,767,250	$29,767,250	$29,767,250	$29,767,250	$29,767,250	$29,767,250	$29,767,250
46	Prior Period True-up Collected/(Refunded) This Period [2]	$5,568,187	$5,568,187	$5,568,187	$5,568,187	$5,568,187	$5,568,187	$5,568,187	$5,568,187	$5,568,187	$5,568,187	$5,568,187	$5,568,187	$66,818,243
47	Midcourse correction - 2015 Final true-up collected/(refunded) this period	$0	$0	$0	($3,307,472)	($3,307,472)	($3,307,472)	($3,307,472)	($3,307,472)	($3,307,472)	($3,307,472)	($3,307,472)	($3,307,472)	($29,767,250)
48	Vendor Settlement Refund per Order No. PSC-16-0298-FOF-EI [7]	$0	$0	$0	$0	$0	$0	$7,573,924	$7,573,924	$7,573,924	$7,573,924	$7,573,924	$7,573,924	$7,573,924
49	End of Period Net True-up Amount Over/(Under) Recovery (Lines 42 through 47)	$23,011,388	$50,007,100	$80,495,039	$69,692,736	$51,835,961	$70,355,106	$25,793,738	$385,590	($4,515,934)	($19,414,083)	($13,366,391)	($18,909,760)	($18,909,760)
50														
51														

52 [1] January through July Actuals include various adjustments as noted on the A-Schedules.

53 [2] Prior Period 2015 Actual/Estimated True-up.

54 [3] Generation Performance Incentive Factor is (($23,303,114/12) x 99.9280%) - See Order No. PSC-15-0586-FOF-EI.

55 [4] 2015 Final True-up.

56 [5] As a result of the Florida Supreme Court's decision, FPL is including a Gas Reserves Refund of $24,532,560 calculated from March 2015 through June 2016. This $24,532,560 consists of $21,294,315 credited to customers in June 2016 plus $3,238,245 that is already reflected in the monthly true-up amounts.

57 [6] FPL has included a refund of $832,856 including resulting from the application of the corrected variable power plant O&M rate to wholesale economy energy sales for the period January 2013 through April 2016.

58 [7] Per Order No. PSC-16-0298-FOF-EI, issued on July 27, 2016, FPL is including a refund of $7,573,924 in the calculation of its 2016 end-of-period net true-up amount, which represents the jurisdictional amount associated with FPL's vendor settlement of $8 million.

59 Note: Totals may not add due to rounding.

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

SCHEDULE: E1-C

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	Annual Total
1. TOTAL AMOUNT OF ADJUSTMENTS	$58,642,605
A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY)	$31,658,059
B. TRUE-UP (OVER)/UNDER RECOVERED	$26,483,684
C. JURISDICTIONALIZED INCENTIVE MECHANISM - FPL PORTION	$500,861
2. TOTAL JURISDICTIONAL SALES (MWH)	107,335,994
3. ADJUSTMENT FACTORS (cents/kWh)	0.0546
A. GENERATING PERFORMANCE INCENTIVE FACTOR	0.0295
B. TRUE-UP FACTOR	0.0247
C. JURISDICTIONALIZED INCENTIVE MECHANISM - FPL PORTION	0.0005

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2017 THROUGH DECEMBER 2017

Line No.	CALCULATION OF JURISDICTIONAIZED 2015 Incentive Mechanism Gains - FPL Portion		Annual Total
1	2015 Incentive Mechanism Gains - FPL Portion [(a)]		$530,626
2			
3	2015 Actual \Retail kWh sales		109,820,398
4	2015 Actual Total System kWh sales		116,430,432
5	2015 Actual Average Jurisdictional % [(b)]		94.32276%
6			
7	Jurisdictionalized 2015 Incentive Mechanism Gains - FPL Portion	$	500,501
8			
9	Revenue Tax Factor		1.00072
10			
11	Jurisdictionalized 2015 Incentive Mechanism Gains - FPL Portion Adjusted for Revenue Taxes	$	500,861
12			
13	2017 Projected kWh Sales		107,335,994
14			
15	2015 Jurisdictional Incentive Mechanism Gains - FPL Portion for Recovery in 2017 CENTS/KWH	$	0.0005
16			
17	[(a)] Reflected on Exhibit GJY-1, filed on March 2, 2016		
18	[(b)] Reflected on Schedule E1-B, filed on March 2, 2016		
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FLORIDA POWER & LIGHT COMPANY
DEVELOPMENT OF MARGINAL TIME OF USE MULTIPLIERS

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	E1-D Schedule - Marginal	Jan - 2017	Feb - 2017	Mar - 2017	Apr - 2017	May - 2017	Jun - 2017	Jul - 2017	Aug - 2017	Sep - 2017	Oct - 2017	Nov - 2017	Dec - 2017	Total
1	Full Year (January - December)													
2	On-Peak Period													
3	System MWH Requirements	2,297,641	2,109,265	2,357,069	2,929,259	3,477,349	3,704,161	3,607,572	4,138,017	3,448,426	3,388,337	2,157,503	2,075,644	35,690,243
4	Marginal Cost	$60,140,201	$55,581,896	$62,552,885	$90,915,258	$114,011,027	$108,783,736	$128,754,232	$155,245,607	$107,001,785	$92,510,850	$53,540,994	$57,622,353	$1,086,660,826
5	Average Marginal Cost (¢/kWh)	2.617	2.635	2.654	3.104	3.279	2.937	3.569	3.752	3.103	2.730	2.482	2.776	3.045
6	Off-Peak Period													
7	System MWH Requirements	7,137,917	6,350,587	6,882,730	6,502,053	7,136,403	7,373,514	8,223,656	7,856,710	7,629,126	6,996,852	6,522,452	6,868,127	85,480,127
8	Marginal Cost	$168,724,007	$164,760,275	$177,926,921	$156,799,181	$186,679,670	$188,071,211	$204,904,491	$203,510,009	$197,429,358	$179,924,687	$153,130,740	$169,638,396	$2,151,498,944
9	Average Marginal Cost (¢/kWh)	2.364	2.594	2.585	2.412	2.616	2.551	2.492	2.590	2.588	2.572	2.348	2.470	2.517
10	Total Period													
11	System MWH Requirements	9,435,558	8,459,852	9,239,798	9,431,313	10,613,752	11,077,675	11,831,228	11,994,727	11,077,552	10,385,189	8,679,954	8,943,772	121,170,370
12	Marginal Cost	$228,864,208	$220,342,171	$240,479,806	$247,714,439	$300,690,697	$296,854,947	$333,658,723	$358,755,616	$304,431,142	$272,435,537	$206,671,734	$227,260,749	$3,238,159,769
13	Average Marginal Cost (¢/kWh)	2.426	2.605	2.603	2.627	2.833	2.680	2.820	2.991	2.748	2.623	2.381	2.541	2.672
14														
15	Full Year Multiplier													
16	On-Peak Period													
17	Marginal Fuel Cost Weighting Multiplier													1.139
18	Off-Peak Period													
19	Marginal Fuel Cost Weighting Multiplier													0.942
20	Average													
21	Marginal Fuel Cost Weighting Multiplier													1.000
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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 2017 THROUGH DECEMBER 2017

Line No.	(1)	(2) Jun - 2017	(3) Jul - 2017	(4) Aug - 2017	(5) Sep - 2017	(6) Total
1	June - September					
2	*On-Peak Period*					
3	System MWH Requirements	1,275,299	1,318,131	1,440,597	1,266,129	5,300,155
4	Marginal Cost	$41,122,777	$58,568,936	$63,861,657	$48,203,336	$211,756,705
5	Average Marginal Cost (¢/kWh)	3.225	4.443	4.433	3.807	3.995
6	*Off-Peak Period*					
7	System MWH Requirements	9,802,376	10,513,097	10,554,130	9,811,423	40,681,027
8	Marginal Cost	$254,816,071	$272,905,024	$291,090,424	$256,277,816	$1,075,089,334
9	Average Marginal Cost (¢/kWh)	2.600	2.596	2.758	2.612	2.643
10	*Total Period*					
11	System MWH Requirements	11,077,675	11,831,228	11,994,727	11,077,552	45,981,182
12	Marginal Cost	$295,938,848	$331,473,960	$354,952,080	$304,481,151	$1,286,846,039
13	Average Marginal Cost (¢/kWh)	2.671	2.802	2.959	2.749	2.799
14						
15	June - September Multiplier					
16	*On-Peak Period*					
17	Marginal Fuel Cost Weighting Multiplier					1.428
18	*Off-Peak Period*					
19	Marginal Fuel Cost Weighting Multiplier					0.944
20	*Average*					
21	Marginal Fuel Cost Weighting Multiplier					1.000
22						
23						
24	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 2017 THROUGH DECEMBER 2017

(1)	(2)	(3)	(4)	(5)
GROUPS	RATE SCHEDULE	JANUARY - DECEMBER		
		Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
A	RS-1 first 1,000 kWh	2.813	1.00252	2.491
A	RS-1 all additional kWh	2.813	1.00252	3.491
A	GS-1, SL-2, GSCU-1, WIES-1, SL-2M	2.813	1.00252	2.820
A-1	SL-1, OL-1, PL-1, SL-1M [1]	2.739	1.00252	2.745
B	GSD-1	2.813	1.00246	2.820
C	GSLD-1, CS-1	2.813	1.00171	2.818
D	GSLD-2, CS-2, OS-2, MET	2.813	0.99482	2.798
E	GSLD-3, CS-3	2.813	0.97229	2.735
A	GST-1 On-Peak	3.204	1.00252	3.212
	GST-1 Off-Peak	2.650	1.00252	2.657
A	RTR-1 On-Peak	-	-	0.392
	RTR-1 Off-Peak	-	-	(0.163)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On-Peak	3.204	1.00246	3.212
	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off-Peak	2.650	1.00246	2.657
C	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) On-Peak	3.204	1.00171	3.209
	GSLDT-1, CST-1, HLFT-2 (500-1,999 kW) Off-Peak	2.650	1.00171	2.655
D	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) On-Peak	3.204	0.99535	3.189
	GSLDT-2, CST-2, HLFT-3 (2,000+ kW) Off-Peak	2.650	0.99535	2.638
E	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) On-Peak	3.204	0.97229	3.115
	GSLDT-3, CST-3, CILC-1(T), ISST-1(T) Off-Peak	2.650	0.97229	2.577
F	CILC-1(D), ISST-1(D) On-Peak	3.204	0.99450	3.186
	CILC-1(D), ISST-1(D) Off-Peak	2.650	0.99450	2.635

[1] WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

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

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

OFF PEAK: ALL OTHER HOURS

(1)	(2)	(3)	(4)	(5)
GROUPS	RATE SCHEDULE	JUNE - SEPTEMBER		
		Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
B	GSD(T)-1 On-Peak	4.017	1.00246	4.027
	GSD(T)-1 Off-Peak	2.655	1.00246	2.662
C	GSLD(T)-1 On-Peak	4.017	1.00171	4.024
	GSLD(T)-1 Off-Peak	2.655	1.00171	2.660
D	GSLD(T)-2 On-Peak	4.017	0.99535	3.998
	GSLD(T)-2 Off-Peak	2.655	0.99535	2.643

Note: On-Peak Period is defined as June through September, weekdays 3:00pm to 6:00pm
Off Peak Period is defined as all other hours.

Note: All other months served under the otherwise applicable rate schedule.
See Schedule E-1E, Page 1 of 2.

Note: Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
2017 PROJECTED ENERGY LOSSES BY RATE CLASS

Line No.	Rate Class/Voltage Level	(1) Delivered MWH Sales	(2) Expansion Factor	(3) Delivered Energy at Generation	(4) Delivered Efficiency	(5) Losses	(6) Fuel Cost Recovery Multiplier
1	RS(T)-1						
2	Secondary	57,023,787	1.048628	59,796,756	0.953627	2,772,969	
3	**Total**	57,023,787	1.048628	59,796,756	0.953627	2,772,969	1.00252
4							
5	CILC-1D						
6	Primary	1,027,307	1.026692	1,054,728	0.974002	27,421	
7	Secondary	1,659,061	1.048628	1,739,739	0.953627	80,677	
8	**Total**	2,686,368	1.040240	2,794,466	0.961317	108,098	0.99450
9							
10	CILC-1G						
11	Primary	1,364	1.026692	1,401	0.974002	36	
12	Secondary	100,221	1.048628	105,095	0.953627	4,874	
13	**Total**	101,585	1.048334	106,495	0.953895	4,910	1.00224
14							
15	CILC-1T						
16	Transmission	1,507,340	1.017005	1,532,972	0.983279	25,633	
17	**Total**	1,507,340	1.017005	1,532,972	0.983279	25,633	0.97229
18							
19	GS(T)-1						
20	Secondary	5,967,155	1.048628	6,257,328	0.953627	290,173	
21	**Total**	5,967,155	1.048628	6,257,328	0.953627	290,173	1.00252
22							
23	GSCU-1						
24	Secondary	70,193	1.048628	73,606	0.953627	3,413	
25	**Total**	70,193	1.048628	73,606	0.953627	3,413	1.00252
26							
27	GSD(T)-1						
28	Primary	74,834	1.026692	76,831	0.974002	1,997	
29	Secondary	25,743,513	1.048628	26,995,377	0.953627	1,251,863	
30	**Total**	25,818,347	1.048565	27,072,208	0.953685	1,253,861	1.00246
31							
32	GSLD(T)-1						
33	Primary	403,576	1.026692	414,349	0.974002	10,772	
34	Secondary	10,100,939	1.048628	10,592,131	0.953627	491,191	
35	**Total**	10,504,516	1.047786	11,006,479	0.954394	501,964	1.00171
36							
37	GSLD(T)-2						
38	Primary	859,389	1.026692	882,328	0.974002	22,939	
39	Secondary	1,655,308	1.048628	1,735,803	0.953627	80,495	
40	**Total**	2,514,698	1.041132	2,618,132	0.960493	103,434	0.99535
41							
42	GSLD(T)-3						
43	Transmission	172,876	1.017005	175,816	0.983279	2,940	
44	**Total**	172,876	1.017005	175,816	0.983279	2,940	0.97229
45							
46	MET						
47	Primary	91,145	1.026692	93,578	0.974002	2,433	
48	**Total**	91,145	1.026692	93,578	0.974002	2,433	0.98155
49							
50	OL-1						
51	Secondary	97,832	1.048628	102,589	0.953627	4,757	
52	**Total**	97,832	1.048628	102,589	0.953627	4,757	1.00252
53							
54	OS-2						
55	Primary	10,786	1.026692	11,074	0.974002	288	
56	**Total**	10,786	1.026692	11,074	0.974002	288	0.98155

FLORIDA POWER & LIGHT COMPANY
2017 PROJECTED ENERGY LOSSES BY RATE CLASS

Line No.	(1) Rate Class/Voltage Level	(2) Delivered MWH Sales	(3) Expansion Factor	(4) Delivered Energy at Generation	(5) Delivered Efficiency	(6) Losses	(7) Fuel Cost Recovery Multiplier
1							
2	SL-1						
3	Secondary	560,461	1.048628	587,715	0.953627	27,254	
4	**Total**	560,461	1.048628	587,715	0.953627	27,254	1.00252
5							
6	SL-2						
7	Secondary	32,740	1.048628	34,332	0.953627	1,592	
8	**Total**	32,740	1.048628	34,332	0.953627	1,592	1.00252
9							
10	SST-DST						
11	Primary	11,849	1.026692	12,165	0.974002	316	
12	**Total**	11,849	1.026692	12,165	0.974002	316	0.98155
13							
14	SST-TST						
15	Transmission	89,605	1.017005	91,129	0.983279	1,524	
16	**Total**	89,605	1.017005	91,129	0.983279	1,524	0.97229
17							
18	Total Retail						
19	**Total**	107,261,283	1.047599	112,366,841	0.954563	5,105,558	1.00153
20							
21	FKEC						
22	Transmission	808,784	1.017005	822,537	0.983279	13,754	
23	**Total**	808,784	1.017005	822,537	0.983279	13,754	0.97229
24							
25	SEMINOLE						
26	Transmission	1,095,042	1.017005	1,113,664	0.983279	18,621	
27	**Total**	1,095,042	1.017005	1,113,664	0.983279	18,621	0.97229
28							
29	LCEC						
30	Transmission	3,998,552	1.017005	4,066,548	0.983279	67,996	
31	**Total**	3,998,552	1.017005	4,066,548	0.983279	67,996	0.97229
32							
33	WAUCHULA						
34	Transmission	4,449	1.017005	4,525	0.983279	76	
35	**Total**	4,449	1.017005	4,525	0.983279	76	0.97229
36							
37	Total Wholesale						
38	**Total**	5,947,873	1.017005	6,049,017	0.983279	101,145	0.97229
39							
40	Total Company						
41	**Total**	113,209,156	1.045992	118,415,858	0.956030	5,206,703	1.00000
42							
43	Company Use						
44	**Total**	130,715	1.048628	137,072	0.953627	6,356	1.00252
45							
46	Total FPL						
47	**Total**	113,339,871	1.045995	118,552,930	0.956028	5,213,059	1.00000
48							
49	Homestead						
50	Transmission	167	1.017005	170	0.983279	3	
51	**Total**	167	1.017005	170	0.983279	3	0.97229
52							
53	BLOUNTSTOWN						
54	Transmission	2,908	1.017005	2,957	0.983279	49	
55	**Total**	2,908	1.017005	2,957	0.983279	49	0.97229
56							

FLORIDA POWER & LIGHT COMPANY
2017 PROJECTED ENERGY LOSSES BY RATE CLASS

Line No.	(1) Rate Class/Voltage Level	(2) Delivered MWH Sales	(3) Expansion Factor	(4) Delivered Energy at Generation	(5) Delivered Efficiency	(6) Losses	(7) Fuel Cost Recovery Multiplier
1	WINTER PARK						
2	Transmission	18,985	1.017005	19,308	0.983279	323	
3	**Total**	18,985	1.017005	19,308	0.983279	323	0.97229
4							
5	New Smryna Beach						
6	Transmission	18,834	1.017005	19,155	0.983279	320	
7	**Total**	18,834	1.017005	19,155	0.983279	320	0.97229
8							
9	Quincy						
10	Transmission	151	1.017005	154	0.983279	3	
11	**Total**	151	1.017005	154	0.983279	3	0.97229
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FLORIDA POWER & LIGHT COMPANY
2017 PROJECTED ENERGY LOSSES BY RATE CLASS GROUP

Line No.	(1) RATE CLASS GROUPS	(2) Delivered MWH Sales	(3) Expansion Factor	(4) Delivered Energy at Generation	(5) Delivered Efficiency	(6) Losses	(7) Fuel Cost Recovery Multiplier
1	GSD1/GSDT1/HLFT1	25,818,347	1.048565	27,072,208	0.953685	1,253,861	1.00246
2	GSLD1/GSLDT1/CS1/CST1/HLFT2	10,504,516	1.047786	11,006,479	0.954394	501,964	1.00171
3	GSLD2/GSLDT2/CS2/CST2/HLFT3	2,514,698	1.041132	2,618,132	0.960493	103,434	0.99535
4	GSLD3/GSLDT3/CS3/CST3	172,876	1.017005	175,816	0.983279	2,940	0.97229
5	CILC D/CILC G	2,787,954	1.040534	2,900,962	0.961045	113,008	0.99478
6	OL1/SL1/PL1	658,293	1.048628	690,304	0.953627	32,012	1.00252
7	SL2, GSCU1	102,933	1.048628	107,938	0.953627	5,005	1.00252
8	GSD-1/GSDT-1/HLFT-1/SDTR-1/CILC-1G	25,919,932	1.048564	27,178,703	0.953685	1,258,771	1.00246
9	GSLDT-2/CS-2/HLFT-3/SDTR-3/OS-2/MET	2,616,629	1.040569	2,722,783	0.961013	106,154	0.99482
10	GSLD-3/GSLDT-3/CS-3/CST-3/CILC-1T	1,680,216	1.017005	1,708,788	0.983279	28,572	0.97229
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FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

SCHEDULE: E2

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line No.		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
1	Fuel Cost of System Generation	$220,997,770	$202,022,040	$230,759,653	$230,451,907	$250,820,617	$257,786,595	$297,708,969	$303,865,076	$282,040,317	$275,727,606	$226,802,257	$230,825,547	$3,009,808,353
2	Cedar Bay – Rail Coal Cars Lease per Docket No. 150075-EI	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	720,000
3	Fuel Cost of Power Sold	(14,184,447)	(12,005,993)	(6,709,912)	(4,643,774)	(3,094,276)	(2,184,862)	(2,243,990)	(2,645,181)	(2,715,413)	(2,170,659)	(2,710,991)	(4,315,413)	(59,624,910)
4	Gain on Economy Sales	(3,554,552)	(2,577,176)	(827,784)	(859,000)	(678,375)	(488,625)	(605,625)	(605,000)	(683,125)	(362,750)	(490,500)	(711,000)	(12,443,512)
5	Fuel Cost of Purchased Power	8,581,424	7,432,894	6,234,583	8,025,084	9,404,834	8,468,190	9,475,844	9,864,257	9,278,016	10,338,336	8,616,171	9,534,454	105,254,087
6	Qualifying Facilities	2,226,780	1,989,948	1,841,604	2,465,140	3,963,985	2,082,096	5,475,876	5,720,658	5,262,148	5,074,350	4,727,249	4,996,418	45,826,252
7	Energy Cost of Economy Purchases	252,970	110,536	558,000	623,759	5,211,422	6,203,854	8,422,644	8,195,879	3,647,301	2,156,221	654,507	456,049	36,493,143
8	Total Fuel & Net Power Transactions	$214,379,945	$197,032,249	$231,916,144	$236,123,116	$265,688,208	$271,927,248	$318,293,717	$324,455,689	$296,889,245	$290,823,104	$237,658,693	$240,846,054	$3,126,033,412
9														
10	Incremental Personnel, Software and Hardware Costs	37,533	38,460	41,494	38,460	42,437	39,977	38,460	41,494	39,977	38,460	39,977	39,977	476,708
11	Variable Power Plant O&M Costs over 514,000 MW Threshold	364,130	293,540	142,935	89,375	(55,770)	(109,200)	(165,750)	(137,930)	(39,000)	(15,795)	41,730	88,075	496,340
12	Total	401,663	332,000	184,429	127,835	(13,333)	(69,223)	(127,290)	(96,436)	977	22,665	81,707	128,052	973,048
13														
14	Dodd Frank Fees	375	375	375	375	375	375	375	375	375	375	375	375	4,500
15														
16	Adjusted Total Fuel & Net Power Transactions	214,781,983	197,364,624	232,100,948	236,251,327	265,675,250	271,858,400	318,166,803	324,359,628	296,890,597	290,846,144	237,740,775	240,974,481	3,127,010,961
17														
18	System MWH Sales	9,007,956	8,072,182	8,084,410	8,361,889	9,421,408	10,279,160	10,919,270	11,071,964	10,817,128	9,997,597	8,740,109	8,550,433	113,323,506
19														
20	Cost per KWH (¢/KWH)	2.3844	2.4450	2.8710	2.8253	2.8199	2.6448	2.9138	2.9296	2.7446	2.9092	2.7201	2.8183	2.7594
21	Jurisdictional Loss Multiplier	1.00153	1.00153	1.00153	1.00153	1.00153	1.00153	1.00153	1.00153	1.00153	1.00153	1.00153	1.00153	1.00153
22	Jurisdictional Cost (¢/KWH)	2.3880	2.4487	2.8754	2.8297	2.8242	2.6488	2.9183	2.9340	2.7488	2.9136	2.7243	2.8226	2.7636
23	True-Up (¢/KWH)	0.0256	0.0288	0.0288	0.0281	0.0249	0.0227	0.0213	0.0210	0.0215	0.0233	0.0268	0.0271	0.0247
24	Total (¢/KWH)	2.4136	2.4775	2.9042	2.8578	2.8491	2.6715	2.9396	2.9550	2.7703	2.9369	2.7511	2.8497	2.7883
25	Revenue Tax Factor (0.00072)	0.0017	0.0018	0.0021	0.0021	0.0021	0.0019	0.0021	0.0021	0.0020	0.0021	0.0020	0.0021	0.0020
26	Recovery Factor Adjusted for Taxes (¢/KWH)	2.4153	2.4793	2.9063	2.8599	2.8512	2.6734	2.9417	2.9571	2.7723	2.9390	2.7531	2.8518	2.7903
27	GPIF (¢/KWH)	0.0307	0.0345	0.0344	0.0336	0.0297	0.0271	0.0255	0.0252	0.0257	0.0279	0.0320	0.0324	0.0295
28	Jurisdictionalized Incentive Mechanism - FPL Portion (¢/KWH)	0.0005	0.0005	0.0005	0.0005	0.0005	0.0004	0.0004	0.0004	0.0004	0.0004	0.0005	0.0005	0.0005
29	Jurisdictionalized Vendor Refund Settlement (¢/KWH)	(0.0073)	(0.0082)	(0.0082)	(0.0080)	(0.0071)	(0.0065)	(0.0061)	(0.0060)	(0.0062)	(0.0067)	(0.0077)	(0.0078)	(0.0071)
30	Recovery Factor including GPIF (¢/KWH)	2.4392	2.5061	2.9330	2.8860	2.8743	2.6944	2.9615	2.9767	2.7923	2.9607	2.7780	2.8770	2.8132
31														
32	Recovery Factor Rounded to .001 (¢/KWH)	2.439	2.506	2.933	2.886	2.874	2.694	2.962	2.977	2.792	2.961	2.778	2.877	2.813
33														
34	Note: Totals may not add due to rounding.													
35														
36														
37														
38														
39														
40														
41														

FLORIDA POWER & LIGHT COMPANY
RS-1 INVERTED RATE COMPUTATION
ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

Line No.	(1)	(2) RS-1 Standard	(3) Proposed Inverted Fuel Factors	(4) Target Fuel Revenues	(5) Rounded
1	First 1000 KWH	38,312,402,402	0.024914	$954,514,954.66	2.491
2	All Additional KWH	18,751,103,656	0.034914	$654,675,916.18	3.491
3	Total KWH	57,063,506,058		$1,609,190,870.84	
4					
5	Avg Fuel Factor	2.813			
6	RS-1 Loss Multiplier	1.00252			
7	Average Fuel Factor	2.820			
8					
9	Target Fuel Revenues	$1,609,190,870.84			
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

SCHEDULE: E3

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

Line No.		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
1	**Fuel Cost of System Net Generation ($)**													
2	Heavy Oil	833,461	540,835	527,678	817,243	2,410,865	2,779,368	1,919,402	3,156,976	1,001,683	865,707	30,125	139,286	15,022,630
3	Light Oil	1,330,027	679,803	2,299,387	2,861,408	3,537,347	2,393,469	2,258,720	1,844,156	1,483,427	2,687,275	1,501,212	908,465	23,784,696
4	Coal	12,655,071	11,852,780	12,106,422	12,334,332	13,107,341	11,697,261	13,551,193	13,685,098	13,159,689	14,606,853	11,918,764	13,503,883	154,178,686
5	Gas	187,661,398	173,559,532	202,061,684	201,089,272	214,489,243	224,197,958	262,703,831	267,903,024	249,676,979	244,227,057	196,726,403	199,093,967	2,623,390,342
6	Nuclear	18,517,813	15,389,090	13,764,482	13,349,653	17,275,823	16,718,540	17,275,823	17,275,823	16,718,540	13,340,715	16,625,753	17,179,946	193,431,998
7	**Total Fuel Cost of System Net Generatic**	220,997,770	202,022,040	230,759,653	230,451,907	250,820,617	257,786,595	297,708,969	303,865,076	282,040,317	275,727,606	226,802,257	230,825,547	3,009,808,353
8														
9	**System Net Generation (MWh)**													
10	Heavy Oil	4,837	3,882	3,313	5,129	16,675	18,386	12,926	21,697	6,594	5,531	167	774	99,911
11	Light Oil	9,948	5,140	20,378	23,561	30,232	23,499	21,132	18,231	16,183	24,698	17,482	10,439	220,923
12	Coal	456,236	437,001	463,614	454,519	473,490	423,029	489,817	485,621	467,774	516,461	424,285	484,919	5,576,764
13	Gas	6,058,513	5,601,003	6,584,763	6,666,724	7,020,247	7,626,064	8,071,497	8,268,093	7,633,842	7,405,936	5,348,315	5,456,082	81,741,079
14	Nuclear	2,575,172	2,144,989	1,934,097	1,930,594	2,504,806	2,424,006	2,504,806	2,504,806	2,424,006	1,928,464	2,492,102	2,575,172	27,943,020
15	Solar	24,684	21,224	30,007	48,270	54,839	53,580	50,902	48,205	43,350	40,796	34,920	31,434	482,211
16	**Total System Net Generation (MWh)**	9,129,389	8,213,240	9,036,171	9,128,796	10,100,289	10,568,563	11,151,080	11,346,654	10,591,749	9,921,886	8,317,271	8,558,820	116,063,908
17														
18	**Units of Fuel Burned (Unit)** [(a)]													
19	Heavy Oil	11,683	7,640	7,473	11,259	33,270	39,538	27,409	44,783	14,346	12,207	444	1,909	211,962
20	Light Oil	12,662	6,459	24,145	30,924	39,397	26,758	26,855	22,401	18,823	32,988	20,172	11,990	273,574
21	Coal	274,917	262,999	281,485	276,112	286,678	257,588	295,375	292,788	282,264	310,398	256,711	290,839	3,368,153
22	Gas	42,428,295	39,512,841	46,899,039	47,807,528	51,798,365	54,983,600	58,482,050	59,955,640	55,260,875	53,967,411	38,974,961	38,922,263	588,992,868
23	Nuclear	28,424,310	23,707,864	21,424,632	20,736,862	27,134,946	26,259,626	27,134,946	27,134,946	26,259,626	20,683,951	26,318,769	27,196,060	302,416,541
24														
25														
26	**BTU Burned (MMBTU)**													
27	Heavy Oil	74,770	48,899	47,828	72,059	212,928	253,046	175,415	286,612	91,817	78,123	2,842	12,217	1,356,556
28	Light Oil	73,819	37,654	140,768	180,288	229,686	155,999	156,567	130,595	109,738	192,321	117,600	69,900	1,594,935
29	Coal	4,936,562	4,694,499	4,947,920	4,928,172	5,164,901	4,634,589	5,310,435	5,277,806	5,073,806	5,590,570	4,617,240	5,240,013	60,416,512
30	Gas	42,428,295	39,512,841	46,899,039	47,807,528	51,798,365	54,983,600	58,482,050	59,955,640	55,260,875	53,967,411	38,974,961	38,922,263	588,992,868
31	Nuclear	28,424,310	23,707,864	21,424,632	20,736,862	27,134,946	26,259,626	27,134,946	27,134,946	26,259,626	20,683,951	26,318,769	27,196,060	302,416,541
32	**Total BTU Burned (MMBTU)**	75,937,756	68,001,757	73,460,187	73,724,910	84,540,827	86,286,860	91,259,413	92,785,599	86,795,862	80,512,376	70,031,412	71,440,453	954,777,412
33														
34	**Fuel Cost per Unit ($/Unit)**													
35	Heavy Oil	71.3408	70.7856	70.6100	72.5844	72.4636	70.2954	70.0292	70.4948	69.8212	70.9205	67.8397	72.9663	70.8742
36	Light Oil	105.0415	105.2544	95.2306	92.5298	89.7866	89.4488	84.1067	82.3265	78.8094	81.4618	74.4223	75.7704	86.9407
37	Coal	46.0323	45.0678	43.0092	44.6716	45.7214	45.4108	45.8779	46.7407	46.6220	47.0585	46.4287	46.4308	45.7754
38	Gas	4.4230	4.3925	4.3084	4.2062	4.1408	4.0775	4.4920	4.4684	4.5182	4.5255	5.0475	5.1152	4.4540
39	Nuclear	0.6515	0.6491	0.6425	0.6438	0.6367	0.6367	0.6367	0.6367	0.6367	0.6450	0.6317	0.6317	0.6396
40	**Total Fuel Cost per Unit ($/Unit)**													
41														
42	**Generation Mix (%)**													
43	Heavy Oil	0.05%	0.05%	0.04%	0.06%	0.17%	0.17%	0.12%	0.19%	0.06%	0.06%	0.00%	0.01%	0.09%

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

SCHEDULE: E3

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

Line No.		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
1	Light Oil	0.11%	0.06%	0.23%	0.26%	0.30%	0.22%	0.19%	0.16%	0.15%	0.25%	0.21%	0.12%	0.19%
2	Coal	5.00%	5.32%	5.13%	4.98%	4.69%	4.00%	4.39%	4.28%	4.42%	5.21%	5.10%	5.67%	4.80%
3	Gas	66.36%	68.19%	72.87%	73.03%	69.51%	72.16%	72.38%	72.87%	72.07%	74.64%	64.30%	63.75%	70.43%
4	Nuclear	28.21%	26.12%	21.40%	21.15%	24.80%	22.94%	22.46%	22.08%	22.89%	19.44%	29.96%	30.09%	24.08%
5	Solar	0.27%	0.26%	0.33%	0.53%	0.54%	0.51%	0.46%	0.42%	0.41%	0.41%	0.42%	0.37%	0.42%
6	**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%
7														
8	**Fuel Cost per MMBTU ($/MMBTU)**													
9	Heavy Oil	11.1470	11.0603	11.0328	11.3413	11.3224	10.9836	10.9421	11.0148	10.9096	11.0813	10.6000	11.4010	11.0741
10	Light Oil	18.0174	18.0539	16.3346	15.8713	15.4008	15.3428	14.4265	14.1212	13.5179	13.9729	12.7654	12.9966	14.9126
11	Coal	2.5635	2.5248	2.4468	2.5028	2.5378	2.5239	2.5518	2.5930	2.5937	2.6128	2.5814	2.5771	2.5519
12	Gas	4.4230	4.3925	4.3084	4.2062	4.1408	4.0775	4.4920	4.4684	4.5182	4.5255	5.0475	5.1152	4.4540
13	Nuclear	0.6515	0.6491	0.6425	0.6438	0.6367	0.6367	0.6367	0.6367	0.6367	0.6450	0.6317	0.6317	0.6396
14														
15	**BTU Burned per KWH (BTU/KWH)**													
16	Heavy Oil	15,459	12,597	14,434	14,050	12,769	13,763	13,571	13,210	13,923	14,124	17,023	15,789	13,578
17	Light Oil	7,421	7,326	6,908	7,652	7,597	6,638	7,409	7,163	6,781	7,787	6,727	6,696	7,219
18	Coal	10,820	10,743	10,673	10,843	10,908	10,956	10,842	10,868	10,847	10,825	10,882	10,806	10,834
19	Gas	7,003	7,055	7,122	7,171	7,378	7,210	7,246	7,251	7,239	7,287	7,287	7,134	7,206
20	Nuclear	11,038	11,053	11,077	10,741	10,833	10,833	10,833	10,833	10,833	10,726	10,561	10,561	10,823
21														
22	**Generated Fuel Cost per KWH (cents/KWH)**													
23	Heavy Oil	17.2319	13.9331	15.9253	15.9351	14.4580	15.1167	14.8493	14.5502	15.1897	15.6508	18.0443	18.0015	15.0360
24	Light Oil	13.3702	13.2260	11.2837	12.1448	11.7007	10.1853	10.6886	10.1153	9.1668	10.8803	8.5871	8.7025	10.7661
25	Coal	2.7738	2.7123	2.6113	2.7137	2.7682	2.7651	2.7666	2.8181	2.8133	2.8283	2.8091	2.7848	2.7647
26	Gas	3.0975	3.0987	3.0686	3.0163	3.0553	2.9399	3.2547	3.2402	3.2707	3.2977	3.6783	3.6490	3.2094
27	Nuclear	0.7191	0.7174	0.7117	0.6915	0.6897	0.6897	0.6897	0.6897	0.6897	0.6918	0.6671	0.6671	0.6922
28	**Total Generated Fuel Cost per KWH (ce**	2.4207	2.4597	2.5537	2.5245	2.4833	2.4392	2.6698	2.6780	2.6628	2.7790	2.7269	2.6969	2.5932
29														
30														
31	[(a)] Fuel Units: Heavy Oil - BBLS, Light Oil - BBLS, Coal - TONS, Gas - MMCF, Nuclear - OTHER													
32														
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37														
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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 - 2017**												
2	*Babcock PV Solar*												
3	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	75	0	11.3%	N/A	30.2%	N/A			0	0	0.00	
5	*CCEC 3*												
6	Light Oil		0					0	0	0	0	0.00	0.00
7	Gas		831,360					5,431,883	1,000,000	5,431,883	24,209,913	2.91	4.46
8	Plant Unit Info	1,234	831,360	90.6%	93.8%	90.6%	6,534			5,431,883	24,209,913	2.91	
9	*Citrus PV Solar*												
10	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75	0	11.3%	N/A	30.2%	N/A			0	0	0.00	
12	*Desoto Solar*												
13	Solar		3,100					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	25	3,100	16.7%	N/A	40.0%	N/A			0	0	0.00	
15	*Fort Myers 2*												
16	Gas		603,871					4,569,244	1,000,000	4,569,244	20,365,387	3.37	4.46
17	Plant Unit Info	1,669	603,871	48.6%	94.0%	48.6%	7,567			4,569,244	20,365,387	3.37	
18	*Fort Myers 3A*												
19	Light Oil		0					0	0	0	0	0.00	0.00
20	Gas		410					5,328	1,000,000	5,328	23,754	5.79	4.46
21	Plant Unit Info	184	410	0.3%	95.5%	55.8%	12,995			5,328	23,754	5.79	
22	*Fort Myers 3B*												
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	183	0	0.0%	95.5%	0.0%	0			0	0	0.00	
26	*Fort Myers 4A*												
27	Light Oil		217					439	5,830,000	2,558	45,966	21.21	104.76
28	Gas		2,371					27,988	1,000,000	27,988	124,781	5.26	4.46
29	Plant Unit Info	223	2,588	1.6%	93.9%	68.3%	11,803			30,546	170,747	6.60	
30	*Fort Myers 4B*												
31	Light Oil		6					12	5,830,000	69	1,240	21.28	104.76
32	Gas		2,718					32,192	1,000,000	32,192	143,526	5.28	4.46
33	Plant Unit Info	223	2,724	1.6%	93.9%	67.8%	11,843			32,261	144,766	5.31	
34	*Lauderdale 4*												
35	Light Oil		296					507	5,830,000	2,958	50,997	17.25	100.51
36	Gas		13,613					136,207	1,000,000	136,207	607,267	4.46	4.46
37	Plant Unit Info	441	13,909	4.2%	93.9%	52.6%	10,005			139,165	658,265	4.73	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	*Lauderdale 5*												
2	Light Oil		330					560	5,830,000	3,265	56,290	17.05	100.51
3	Gas		18,226					180,225	1,000,000	180,225	803,513	4.41	4.46
4	Plant Unit Info	441	18,556	5.7%	93.9%	58.5%	9,888			183,490	859,803	4.63	
5	*Lauderdale 6 CT 1*												
6	Light Oil		0					0	0	0	0	0.00	0.00
7	Gas		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	203	0	0.0%	95.5%	0.0%	0			0	0	0.00	
9	*Lauderdale 6 CT 2*												
10	Light Oil		138					278	5,830,000	1,623	27,981	20.22	100.51
11	Gas		3,300					38,696	1,000,000	38,696	172,522	5.23	4.46
12	Plant Unit Info	201	3,438	2.3%	95.5%	77.8%	11,727			40,319	200,504	5.83	
13	*Lauderdale 6 CT 3*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	203	0	0.0%	95.5%	0.0%	0			0	0	0.00	
17	*Lauderdale 6 CT 4*												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	202	0	0.0%	95.5%	0.0%	0			0	0	0.00	
21	*Lauderdale 6 CT 5*												
22	Light Oil		0					0	0	0	0	0.00	0.00
23	Gas		0					0	0	0	0	0.00	0.00
24	Plant Unit Info	201	0	0.0%	95.5%	0.0%	0			0	0	0.00	
25	*Manatee 1*												
26	Heavy Oil		1,646					4,276	6,400,000	27,366	300,187	18.23	70.20
27	Gas		4,841					80,470	1,000,000	80,470	352,180	7.28	4.38
28	Plant Unit Info	786	6,487	1.1%	96.2%	34.4%	16,623			107,836	652,367	10.06	
29	*Manatee 2*												
30	Heavy Oil		1,109					2,598	6,400,000	16,630	182,420	16.45	70.20
31	Gas		1,652					24,771	1,000,000	24,771	108,410	6.56	4.38
32	Plant Unit Info	790	2,761	0.5%	96.3%	43.7%	14,995			41,401	290,831	10.53	
33	*Manatee 3*												
34	Gas		429,566					3,180,223	1,000,000	3,180,223	13,922,832	3.24	4.38
35	Plant Unit Info	1,158	429,566	49.9%	94.1%	68.3%	7,403			3,180,223	13,922,832	3.24	
36	*Manatee PV Solar*												
37	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Plant Unit Info	75	0	11.3%	N/A	30.2%	N/A			0	0	0.00	
2	*Martin 1*												
3	Heavy Oil		1,079					2,500	6,400,000	16,000	182,416	16.91	72.97
4	Gas		1,791					26,571	1,000,000	26,571	117,480	6.56	4.42
5	Plant Unit Info	804	2,870	0.5%	96.3%	44.6%	14,833			42,571	299,896	10.45	
6	*Martin 2*												
7	Heavy Oil		1,003					2,308	6,400,000	14,774	168,438	16.80	72.97
8	Gas		1,912					28,175	1,000,000	28,175	124,632	6.52	4.42
9	Plant Unit Info	784	2,915	0.5%	96.3%	46.5%	14,733			42,949	293,070	10.05	
10	*Martin 3*												
11	Gas		17,743					166,172	1,000,000	166,172	729,185	4.11	4.39
12	Plant Unit Info	479	17,743	5.0%	94.1%	61.8%	9,366			166,172	729,185	4.11	
13	*Martin 4*												
14	Gas		13,467					129,123	1,000,000	129,123	566,399	4.21	4.39
15	Plant Unit Info	433	13,467	4.2%	94.1%	64.8%	9,588			129,123	566,399	4.21	
16	*Martin 8*												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		71,123					495,086	1,000,000	495,086	2,164,095	3.04	4.37
19	Plant Unit Info	1,112	71,123	8.3%	8.3%	44.4%	6,961			495,086	2,164,095	3.04	
20	*Martin 8 Solar*												
21	Solar		1,434					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	75	1,434	2.6%	N/A	29.0%	N/A			0	0	0.00	
23	*PEEC*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		864,211					5,589,745	1,000,000	5,589,745	24,913,275	2.88	4.46
26	Plant Unit Info	1,216	864,211	93.5%	93.5%	95.5%	6,468			5,589,745	24,913,275	2.88	
27	*Riviera 5*												
28	Light Oil		3,931					4,419	5,830,000	25,761	491,581	12.50	111.25
29	Gas		801,360					5,251,069	1,000,000	5,251,069	23,404,423	2.92	4.46
30	Plant Unit Info	1,216	805,291	89.0%	93.8%	89.0%	6,553			5,276,830	23,896,004	2.97	
31	*Sanford 4*												
32	Gas		58,406					513,104	1,000,000	513,104	2,287,622	3.92	4.46
33	Plant Unit Info	1,020	58,406	7.7%	94.1%	45.1%	8,785			513,104	2,287,622	3.92	
34	*Sanford 5*												
35	Gas		85,650					757,096	1,000,000	757,096	3,375,439	3.94	4.46
36	Plant Unit Info	1,020	85,650	11.3%	94.1%	47.7%	8,839			757,096	3,375,439	3.94	
37	*Scherer 4*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Coal		352,028					222,324	17,000,000	3,779,509	8,906,164	2.53	40.06
2	Plant Unit Info	599	352,028	79.0%	95.0%	79.0%	10,736			3,779,509	8,906,164	2.53	
3	*St Johns 1*												
4	Coal		52,838					26,688	22,000,000	587,145	1,902,379	3.60	71.28
5	Plant Unit Info	125	52,838	56.7%	94.8%	56.7%	11,112			587,145	1,902,379	3.60	
6	*St Johns 2*												
7	Coal		51,370					25,905	22,000,000	569,908	1,846,528	3.59	71.28
8	Plant Unit Info	125	51,370	55.2%	94.8%	55.2%	11,094			569,908	1,846,528	3.59	
9	*St Lucie 1*												
10	Nuclear		728,079					7,908,389	1,000,000	7,908,389	4,982,282	0.68	0.63
11	Plant Unit Info	1,004	728,079	97.5%	97.5%	97.5%	10,862			7,908,389	4,982,282	0.68	
12	*St Lucie 2*												
13	Nuclear		623,343					6,770,755	1,000,000	6,770,755	4,604,112	0.74	0.68
14	Plant Unit Info	859	623,343	97.5%	97.5%	97.5%	10,862			6,770,755	4,604,112	0.74	
15	*Space Coast*												
16	Solar		1,178					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	10	1,178	15.8%	N/A	42.2%	N/A			0	0	0.00	
18	*Turkey Point 3*												
19	Nuclear		608,611					6,835,918	1,000,000	6,835,918	4,716,781	0.78	0.69
20	Plant Unit Info	839	608,611	97.5%	97.5%	97.5%	11,232			6,835,918	4,716,781	0.78	
21	*Turkey Point 4*												
22	Nuclear		615,139					6,909,248	1,000,000	6,909,248	4,214,638	0.69	0.61
23	Plant Unit Info	848	615,139	97.5%	97.5%	97.5%	11,232			6,909,248	4,214,638	0.69	
24	*Turkey Point 5*												
25	Light Oil		3,340					4,424	5,830,000	25,790	432,648	12.95	97.80
26	Gas		262,374					2,026,127	1,000,000	2,026,127	9,029,806	3.44	4.46
27	Plant Unit Info	1,155	265,714	30.9%	94.1%	57.9%	7,722			2,051,917	9,462,455	3.56	
28	*WCEC 01*												
29	Light Oil		769					921	5,830,000	5,368	101,636	13.21	110.38
30	Gas		653,710					4,562,168	1,000,000	4,562,168	19,961,339	3.05	4.38
31	Plant Unit Info	1,208	654,479	72.8%	94.0%	72.8%	6,979			4,567,536	20,062,976	3.07	
32	*WCEC 02*												
33	Light Oil		454					542	5,830,000	3,161	59,849	13.17	110.38
34	Gas		677,876					4,714,558	1,000,000	4,714,558	20,629,229	3.04	4.38
35	Plant Unit Info	1,198	678,330	76.1%	94.0%	76.1%	6,955			4,717,719	20,689,078	3.05	
36	*WCEC 03*												
37	Light Oil		466					560	5,830,000	3,266	61,837	13.26	110.38

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Gas		636,963					4,462,074	1,000,000	4,462,074	19,524,389	3.07	4.38
2	Plant Unit Info	1,208	637,429	70.9%	94.0%	70.9%	7,005			4,465,340	19,586,226	3.07	
3	**System Totals**												
4	Plant Unit Info	25,926	9,110,417				8,335			75,937,756	220,997,770	2	
5													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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 - 2017**												
2	*Babcock PV Solar*												
3	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	75	0	10.9%	N/A	29.0%	N/A			0	0	0.00	
5	*CCEC 3*												
6	Light Oil		0					0	0	0	0	0.00	0.00
7	Gas		533,805					3,563,280	1,000,000	3,563,280	15,769,682	2.95	4.43
8	Plant Unit Info	1,234	533,805	64.4%	77.1%	64.4%	6,675			3,563,280	15,769,682	2.95	
9	*Citrus PV Solar*												
10	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75	0	10.9%	N/A	29.0%	N/A			0	0	0.00	
12	*Desoto Solar*												
13	Solar		3,528					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	25	3,528	21.0%	N/A	45.8%	N/A			0	0	0.00	
15	*Fort Myers 2*												
16	Gas		618,030					4,617,669	1,000,000	4,617,669	20,438,698	3.31	4.43
17	Plant Unit Info	1,669	618,030	55.1%	94.0%	55.1%	7,472			4,617,669	20,438,698	3.31	
18	*Fort Myers 3A*												
19	Light Oil		27					55	5,830,000	319	5,732	21.20	104.76
20	Gas		1,542					18,195	1,000,000	18,195	80,810	5.24	4.44
21	Plant Unit Info	182	1,569	1.3%	95.5%	71.7%	11,800			18,514	86,542	5.52	
22	*Fort Myers 3B*												
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	183	0	0.0%	95.5%	0.0%	0			0	0	0.00	
26	*Fort Myers 4A*												
27	Light Oil		19					38	5,830,000	220	3,953	20.63	104.76
28	Gas		10,261					117,785	1,000,000	117,785	521,412	5.08	4.43
29	Plant Unit Info	223	10,280	6.9%	93.9%	74.4%	11,479			118,005	525,365	5.11	
30	*Fort Myers 4B*												
31	Light Oil		13					27	5,830,000	158	2,839	21.17	104.76
32	Gas		2,137					25,168	1,000,000	25,168	111,342	5.21	4.42
33	Plant Unit Info	224	2,150	1.4%	93.9%	68.6%	11,780			25,326	114,181	5.31	
34	*Lauderdale 4*												
35	Light Oil		0					0	0	0	0	0.00	0.00
36	Gas		46,886					417,448	1,000,000	417,448	1,848,560	3.94	4.43
37	Plant Unit Info	441	46,886	15.8%	61.8%	72.8%	8,903			417,448	1,848,560	3.94	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	*Lauderdale 5*												
2	Light Oil		0					0	0	0	0	0.00	0.00
3	Gas		65,629					588,928	1,000,000	588,928	2,607,250	3.97	4.43
4	Plant Unit Info	441	65,629	22.2%	93.9%	72.6%	8,974			588,928	2,607,250	3.97	
5	*Lauderdale 6 CT 1*												
6	Light Oil		0					0	0	0	0	0.00	0.00
7	Gas		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	203	0	0.0%	95.5%	0.0%	0			0	0	0.00	
9	*Lauderdale 6 CT 2*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		12,197					138,753	1,000,000	138,753	614,499	5.04	4.43
12	Plant Unit Info	201	12,197	9.0%	95.5%	84.3%	11,376			138,753	614,499	5.04	
13	*Lauderdale 6 CT 3*												
14	Light Oil		573					1,098	5,830,000	6,401	110,356	19.25	100.51
15	Gas		27					300	1,000,000	300	1,328	4.94	4.43
16	Plant Unit Info	203	600	0.4%	95.5%	73.9%	11,168			6,701	111,683	18.61	
17	*Lauderdale 6 CT 4*												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	202	0	0.0%	95.5%	0.0%	0			0	0	0.00	
21	*Lauderdale 6 CT 5*												
22	Light Oil		0					0	0	0	0	0.00	0.00
23	Gas		0					0	0	0	0	0.00	0.00
24	Plant Unit Info	201	0	0.0%	95.5%	0.0%	0			0	0	0.00	
25	*Manatee 1*												
26	Heavy Oil		1,048					2,073	6,400,000	13,264	145,497	13.89	70.20
27	Gas		4,047					51,240	1,000,000	51,240	222,503	5.50	4.34
28	Plant Unit Info	790	5,095	1.0%	96.2%	64.5%	12,660			64,504	368,000	7.22	
29	*Manatee 2*												
30	Heavy Oil		2,025					3,959	6,400,000	25,336	277,919	13.73	70.20
31	Gas		11,344					141,966	1,000,000	141,966	616,470	5.43	4.34
32	Plant Unit Info	789	13,369	2.5%	96.3%	51.3%	12,514			167,302	894,389	6.69	
33	*Manatee 3*												
34	Gas		380,169					2,733,170	1,000,000	2,733,170	11,877,749	3.12	4.35
35	Plant Unit Info	1,158	380,169	48.9%	94.1%	77.4%	7,189			2,733,170	11,877,749	3.12	
36	*Manatee PV Solar*												
37	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Plant Unit Info	75	0	10.9%	N/A	29.0%	N/A			0	0	0.00	
2	*Martin 1*												
3	Heavy Oil		809					1,609	6,400,000	10,299	117,419	14.51	72.97
4	Gas		18,838					239,705	1,000,000	239,705	1,058,920	5.62	4.42
5	Plant Unit Info	803	19,647	3.6%	96.3%	37.1%	12,725			250,004	1,176,339	5.99	
6	*Martin 2*												
7	Heavy Oil		0					0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	784	0	0.0%	96.3%	0.0%	0			0	0	0.00	
10	*Martin 3*												
11	Gas		69,997					566,849	1,000,000	566,849	2,464,470	3.52	4.35
12	Plant Unit Info	479	69,997	21.8%	94.1%	79.0%	8,098			566,849	2,464,470	3.52	
13	*Martin 4*												
14	Gas		46,832					399,524	1,000,000	399,524	1,736,321	3.71	4.35
15	Plant Unit Info	433	46,832	16.1%	94.1%	80.7%	8,531			399,524	1,736,321	3.71	
16	*Martin 8*												
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	1,112	0	0.0%	0.0%	0.0%	0			0	0	0.00	
20	*Martin 8 Solar*												
21	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	75	0	0.0%	N/A	0.0%	N/A			0	0	0.00	
23	*PEEC*												
24	Light Oil		0					0	0	0	0	0.00	0.00
25	Gas		784,346					5,070,479	1,000,000	5,070,479	22,440,491	2.86	4.43
26	Plant Unit Info	1,216	784,346	93.5%	93.5%	96.0%	6,465			5,070,479	22,440,491	2.86	
27	*Riviera 5*												
28	Light Oil		2,926					3,296	5,830,000	19,215	366,668	12.53	111.25
29	Gas		689,438					4,527,107	1,000,000	4,527,107	20,036,633	2.91	4.43
30	Plant Unit Info	1,216	692,364	84.7%	93.8%	84.7%	6,566			4,546,322	20,403,301	2.95	
31	*Sanford 4*												
32	Gas		99,700					822,787	1,000,000	822,787	3,644,862	3.66	4.43
33	Plant Unit Info	1,020	99,700	14.6%	94.1%	77.0%	8,253			822,787	3,644,862	3.66	
34	*Sanford 5*												
35	Gas		38,492					316,013	1,000,000	316,013	1,401,849	3.64	4.44
36	Plant Unit Info	1,019	38,492	5.6%	69.1%	77.1%	8,210			316,013	1,401,849	3.64	
37	*Scherer 4*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Coal		349,156					218,296	17,000,000	3,711,036	8,612,729	2.47	39.45
2	Plant Unit Info	599	349,156	86.7%	95.0%	86.7%	10,629			3,711,036	8,612,729	2.47	
3	*St Johns 1*												
4	Coal		53,211					27,079	22,000,000	595,744	1,962,700	3.69	72.48
5	Plant Unit Info	125	53,211	63.3%	94.8%	63.3%	11,196			595,744	1,962,700	3.69	
6	*St Johns 2*												
7	Coal		34,634					17,624	22,000,000	387,718	1,277,351	3.69	72.48
8	Plant Unit Info	125	34,634	41.2%	66.2%	57.6%	11,195			387,718	1,277,351	3.69	
9	*St Lucie 1*												
10	Nuclear		657,619					7,143,060	1,000,000	7,143,060	4,500,126	0.68	0.63
11	Plant Unit Info	1,004	657,619	97.5%	97.5%	97.5%	10,862			7,143,060	4,500,126	0.68	
12	*St Lucie 2*												
13	Nuclear		382,049					4,149,816	1,000,000	4,149,816	2,821,875	0.74	0.68
14	Plant Unit Info	859	382,049	66.2%	66.2%	97.5%	10,862			4,149,816	2,821,875	0.74	
15	*Space Coast*												
16	Solar		1,232					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	10	1,232	18.3%	N/A	44.0%	N/A			0	0	0.00	
18	*Turkey Point 3*												
19	Nuclear		549,713					6,174,377	1,000,000	6,174,377	4,260,319	0.78	0.69
20	Plant Unit Info	839	549,713	97.5%	97.5%	97.5%	11,232			6,174,377	4,260,319	0.78	
21	*Turkey Point 4*												
22	Nuclear		555,609					6,240,611	1,000,000	6,240,611	3,806,770	0.69	0.61
23	Plant Unit Info	848	555,609	97.5%	97.5%	97.5%	11,232			6,240,611	3,806,770	0.69	
24	*Turkey Point 5*												
25	Light Oil		1,581					1,945	5,830,000	11,341	190,255	12.03	97.80
26	Gas		412,783					2,961,288	1,000,000	2,961,288	13,107,580	3.18	4.43
27	Plant Unit Info	1,155	414,364	53.4%	94.1%	71.0%	7,174			2,972,629	13,297,835	3.21	
28	*WCEC 01*												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		495,124					3,468,632	1,000,000	3,468,632	15,062,736	3.04	4.34
31	Plant Unit Info	1,208	495,124	61.0%	79.7%	71.2%	7,006			3,468,632	15,062,736	3.04	
32	*WCEC 02*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		660,852					4,553,804	1,000,000	4,553,804	19,775,033	2.99	4.34
35	Plant Unit Info	1,198	660,852	82.1%	94.0%	82.1%	6,891			4,553,804	19,775,033	2.99	
36	*WCEC 03*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Gas		598,528					4,172,751	1,000,000	4,172,751	18,120,333	3.03	4.34
2	Plant Unit Info	1,208	598,528	73.7%	94.0%	73.7%	6,972			4,172,751	18,120,333	3.03	
3	**System Totals**												
4	Plant Unit Info	25,929	8,196,776				8,296			68,001,757	202,022,040	2	
5													
6													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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 - 2017**												
2	*Babcock PV Solar*												
3	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	75	0	10.9%	N/A	29.0%	N/A			0	0	0.00	
5	*CCEC 3*												
6	Light Oil		4,242					4,940	5,830,000	28,800	436,260	10.28	88.31
7	Gas		430,280					2,921,157	1,000,000	2,921,157	12,684,612	2.95	4.34
8	Plant Unit Info	1,234	434,522	47.3%	61.5%	47.3%	6,789			2,949,957	13,120,872	3.02	
9	*Citrus PV Solar*												
10	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75	0	10.9%	N/A	29.0%	N/A			0	0	0.00	
12	*Desoto Solar*												
13	Solar		4,836					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	25	4,836	26.0%	N/A	56.7%	N/A			0	0	0.00	
15	*Fort Myers 2*												
16	Gas		760,991					5,652,051	1,000,000	5,652,051	24,543,396	3.23	4.34
17	Plant Unit Info	1,669	760,991	61.3%	94.0%	61.3%	7,427			5,652,051	24,543,396	3.23	
18	*Fort Myers 3A*												
19	Light Oil		96					191	5,830,000	1,116	20,054	20.83	104.76
20	Gas		4,490					52,039	1,000,000	52,039	225,863	5.03	4.34
21	Plant Unit Info	183	4,586	3.4%	95.5%	69.6%	11,591			53,155	245,917	5.36	
22	*Fort Myers 3B*												
23	Light Oil		91					181	5,830,000	1,056	18,976	20.83	104.76
24	Gas		3,671					42,548	1,000,000	42,548	184,669	5.03	4.34
25	Plant Unit Info	183	3,762	2.8%	95.5%	70.8%	11,591			43,604	203,645	5.41	
26	*Fort Myers 4A*												
27	Light Oil		131					255	5,830,000	1,487	26,721	20.33	104.76
28	Gas		5,717					64,668	1,000,000	64,668	280,675	4.91	4.34
29	Plant Unit Info	223	5,848	3.5%	93.9%	77.0%	11,312			66,155	307,396	5.26	
30	*Fort Myers 4B*												
31	Light Oil		105					202	5,830,000	1,177	21,150	20.16	104.76
32	Gas		638					7,158	1,000,000	7,158	31,067	4.87	4.34
33	Plant Unit Info	222	743	0.5%	93.9%	83.7%	11,218			8,335	52,217	7.03	
34	*Lauderdale 4*												
35	Light Oil		0					0	0	0	0	0.00	0.00
36	Gas		44,351					402,200	1,000,000	402,200	1,745,650	3.94	4.34
37	Plant Unit Info	441	44,351	13.5%	43.9%	68.9%	9,069			402,200	1,745,650	3.94	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	*Lauderdale 5*												
2	Light Oil		0					0	0	0	0	0.00	0.00
3	Gas		49,020					443,164	1,000,000	443,164	1,923,446	3.92	4.34
4	Plant Unit Info	441	49,020	14.9%	93.9%	76.7%	9,040			443,164	1,923,446	3.92	
5	*Lauderdale 6 CT 1*												
6	Light Oil		0					0	0	0	0	0.00	0.00
7	Gas		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	203	0	0.0%	95.5%	0.0%	0			0	0	0.00	
9	*Lauderdale 6 CT 2*												
10	Light Oil		282					552	5,830,000	3,219	55,497	19.66	100.51
11	Gas		6,763					77,118	1,000,000	77,118	334,711	4.95	4.34
12	Plant Unit Info	201	7,045	4.7%	95.5%	85.5%	11,403			80,337	390,208	5.54	
13	*Lauderdale 6 CT 3*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	203	0	0.0%	95.5%	0.0%	0			0	0	0.00	
17	*Lauderdale 6 CT 4*												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	202	0	0.0%	95.5%	0.0%	0			0	0	0.00	
21	*Lauderdale 6 CT 5*												
22	Light Oil		0					0	0	0	0	0.00	0.00
23	Gas		0					0	0	0	0	0.00	0.00
24	Plant Unit Info	201	0	0.0%	95.5%	0.0%	0			0	0	0.00	
25	*Manatee 1*												
26	Heavy Oil		817					1,901	6,400,000	12,165	133,442	16.33	70.20
27	Gas		1,833					27,288	1,000,000	27,288	116,247	6.34	4.26
28	Plant Unit Info	792	2,650	0.5%	5.9%	41.9%	14,888			39,453	249,689	9.42	
29	*Manatee 2*												
30	Heavy Oil		2,021					4,473	6,400,000	28,630	314,052	15.54	70.20
31	Gas		17,142					242,790	1,000,000	242,790	1,036,752	6.05	4.27
32	Plant Unit Info	790	19,164	3.3%	96.3%	37.9%	14,163			271,420	1,350,804	7.05	
33	*Manatee 3*												
34	Gas		254,443					1,843,149	1,000,000	1,843,149	7,864,030	3.09	4.27
35	Plant Unit Info	1,158	254,443	29.5%	48.9%	60.9%	7,244			1,843,149	7,864,030	3.09	
36	*Manatee PV Solar*												
37	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Plant Unit Info	75	0	10.9%	N/A	29.0%	N/A			0	0	0.00	
2	*Martin 1*												
3	Heavy Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	803	0	0.0%	96.3%	0.0%	0			0	0	0.00	
6	*Martin 2*												
7	Heavy Oil		475					1,099	6,400,000	7,033	80,183	16.88	72.97
8	Gas		2,398					35,515	1,000,000	35,515	154,143	6.43	4.34
9	Plant Unit Info	772	2,873	0.5%	96.3%	46.5%	14,810			42,548	234,326	8.16	
10	*Martin 3*												
11	Gas		98,831					832,933	1,000,000	832,933	3,558,474	3.60	4.27
12	Plant Unit Info	479	98,831	27.7%	66.7%	71.4%	8,428			832,933	3,558,474	3.60	
13	*Martin 4*												
14	Gas		135,508					1,150,072	1,000,000	1,150,072	4,910,429	3.62	4.27
15	Plant Unit Info	433	135,508	42.1%	94.1%	83.0%	8,487			1,150,072	4,910,429	3.62	
16	*Martin 8*												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		121,571					855,246	1,000,000	855,246	3,651,332	3.00	4.27
19	Plant Unit Info	1,112	121,571	14.7%	16.4%	65.1%	7,035			855,246	3,651,332	3.00	
20	*Martin 8 Solar*												
21	Solar		5,362					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	75	5,362	9.6%	N/A	39.3%	N/A			0	0	0.00	
23	*PEEC*												
24	Light Oil		2,626					2,930	5,830,000	17,082	220,756	8.41	75.34
25	Gas		815,943					5,308,241	1,000,000	5,308,241	23,049,588	2.82	4.34
26	Plant Unit Info	1,216	818,569	90.5%	93.5%	90.5%	6,506			5,325,323	23,270,344	2.84	
27	*Riviera 5*												
28	Light Oil		10,646					12,164	5,830,000	70,918	1,233,020	11.58	101.36
29	Gas		678,250					4,518,065	1,000,000	4,518,065	19,618,522	2.89	4.34
30	Plant Unit Info	1,216	688,896	76.2%	93.8%	76.2%	6,661			4,588,983	20,851,542	3.03	
31	*Sanford 4*												
32	Gas		256,452					2,103,194	1,000,000	2,103,194	9,133,008	3.56	4.34
33	Plant Unit Info	1,020	256,452	33.8%	94.1%	72.2%	8,201			2,103,194	9,133,008	3.56	
34	*Sanford 5*												
35	Gas		279,154					2,175,204	1,000,000	2,175,204	9,447,667	3.38	4.34
36	Plant Unit Info	1,020	279,154	36.8%	94.1%	71.8%	7,792			2,175,204	9,447,667	3.38	
37	*Scherer 4*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Coal		399,574					248,949	17,000,000	4,232,129	9,724,950	2.43	39.06
2	Plant Unit Info	599	399,574	89.7%	95.0%	89.7%	10,592			4,232,129	9,724,950	2.43	
3	*St Johns 1*												
4	Coal		5,936					3,029	22,000,000	66,627	221,672	3.73	73.20
5	Plant Unit Info	125	5,936	4.5%	4.5%	65.8%	11,224			66,627	221,672	3.73	
6	*St Johns 2*												
7	Coal		58,104					29,507	22,000,000	649,164	2,159,800	3.72	73.20
8	Plant Unit Info	125	58,104	62.4%	94.8%	62.4%	11,173			649,164	2,159,800	3.72	
9	*St Lucie 1*												
10	Nuclear		728,079					7,908,389	1,000,000	7,908,389	4,982,282	0.68	0.63
11	Plant Unit Info	1,004	728,079	97.5%	97.5%	97.5%	10,862			7,908,389	4,982,282	0.68	
12	*St Lucie 2*												
13	Nuclear		80,431					873,645	1,000,000	873,645	611,552	0.76	0.70
14	Plant Unit Info	859	80,431	12.6%	12.6%	97.5%	10,862			873,645	611,552	0.76	
15	*Space Coast*												
16	Solar		1,581					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	10	1,581	21.3%	N/A	46.4%	N/A			0	0	0.00	
18	*Turkey Point 3*												
19	Nuclear		510,448					5,733,350	1,000,000	5,733,350	3,956,010	0.78	0.69
20	Plant Unit Info	839	510,448	81.8%	81.8%	97.5%	11,232			5,733,350	3,956,010	0.78	
21	*Turkey Point 4*												
22	Nuclear		615,139					6,909,248	1,000,000	6,909,248	4,214,638	0.69	0.61
23	Plant Unit Info	848	615,139	97.5%	97.5%	97.5%	11,232			6,909,248	4,214,638	0.69	
24	*Turkey Point 5*												
25	Light Oil		2,158					2,730	5,830,000	15,913	266,954	12.37	97.80
26	Gas		435,053					3,208,409	1,000,000	3,208,409	13,930,032	3.20	4.34
27	Plant Unit Info	1,155	437,211	50.9%	94.1%	78.9%	7,375			3,224,322	14,196,986	3.25	
28	*WCEC 01*												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		596,838					4,125,165	1,000,000	4,125,165	17,573,146	2.94	4.26
31	Plant Unit Info	1,208	596,838	66.4%	74.7%	82.3%	6,912			4,125,165	17,573,146	2.94	
32	*WCEC 02*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		779,166					5,328,997	1,000,000	5,328,997	22,704,813	2.91	4.26
35	Plant Unit Info	1,198	779,166	87.4%	94.0%	87.4%	6,839			5,328,997	22,704,813	2.91	
36	*WCEC 03*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Gas		806,260					5,482,668	1,000,000	5,482,668	23,359,413	2.90	4.26
2	Plant Unit Info	1,208	806,260	89.7%	94.0%	89.7%	6,800			5,482,668	23,359,413	2.90	
3	**System Totals**												
4	Plant Unit Info	25,921	9,017,943				8,146			73,460,187	230,759,653	3	
5													
6													
7													
8													
9													
10													
11													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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 - 2017**												
2	*Babcock PV Solar*												
3	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	75	0	16.6%	N/A	39.7%	N/A			0	0	0.00	
5	*CCEC 3*												
6	Light Oil		4,440					5,146	5,830,000	30,000	454,437	10.23	88.31
7	Gas		465,157					3,142,660	1,000,000	3,142,660	13,321,836	2.86	4.24
8	Plant Unit Info	1,223	469,597	53.3%	60.5%	53.3%	6,756			3,172,660	13,776,273	2.93	
9	*Citrus PV Solar*												
10	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75	0	16.6%	N/A	39.7%	N/A			0	0	0.00	
12	*Desoto Solar*												
13	Solar		5,400					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	25	5,400	30.0%	N/A	60.0%	N/A			0	0	0.00	
15	*Fort Myers 2*												
16	Gas		765,969					5,660,172	1,000,000	5,660,172	23,993,179	3.13	4.24
17	Plant Unit Info	1,470	765,969	72.4%	94.0%	72.4%	7,390			5,660,172	23,993,179	3.13	
18	*Fort Myers 3A*												
19	Light Oil		18					39	5,830,000	228	4,097	22.57	104.76
20	Gas		891					11,190	1,000,000	11,190	47,417	5.32	4.24
21	Plant Unit Info	171	909	0.7%	72.2%	66.6%	12,561			11,418	51,514	5.67	
22	*Fort Myers 3B*												
23	Light Oil		10					21	5,830,000	124	2,228	22.40	104.76
24	Gas		913					11,384	1,000,000	11,384	48,239	5.28	4.24
25	Plant Unit Info	171	923	0.8%	72.2%	67.5%	12,468			11,508	50,468	5.47	
26	*Fort Myers 4A*												
27	Light Oil		127					217	5,830,000	1,264	22,714	17.87	104.76
28	Gas		14,934					148,542	1,000,000	148,542	629,425	4.21	4.24
29	Plant Unit Info	223	15,061	9.4%	93.9%	84.4%	9,947			149,806	652,139	4.33	
30	*Fort Myers 4B*												
31	Light Oil		77					131	5,830,000	766	13,765	17.81	104.76
32	Gas		16,113					159,671	1,000,000	159,671	676,583	4.20	4.24
33	Plant Unit Info	223	16,190	10.1%	93.9%	85.4%	9,910			160,437	690,348	4.26	
34	*Lauderdale 4*												
35	Light Oil		0					0	0	0	0	0.00	0.00
36	Gas		86,077					769,354	1,000,000	769,354	3,261,848	3.79	4.24
37	Plant Unit Info	431	86,077	27.7%	88.9%	77.4%	8,938			769,354	3,261,848	3.79	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	*Lauderdale 5*												
2	Light Oil		0					0	0	0	0	0.00	0.00
3	Gas		31,796					283,095	1,000,000	283,095	1,201,482	3.78	4.24
4	Plant Unit Info	431	31,796	10.3%	33.9%	73.8%	8,903			283,095	1,201,482	3.78	
5	*Lauderdale 6 CT 1*												
6	Light Oil		28					51	5,830,000	300	4,850	17.29	94.25
7	Gas		572					6,117	1,000,000	6,117	25,921	4.53	4.24
8	Plant Unit Info	203	600	0.4%	95.5%	73.8%	10,695			6,417	30,770	5.13	
9	*Lauderdale 6 CT 2*												
10	Light Oil		394					669	5,830,000	3,900	63,049	16.01	94.25
11	Gas		16,017					158,600	1,000,000	158,600	672,043	4.20	4.24
12	Plant Unit Info	201	16,411	11.3%	95.5%	94.9%	9,902			162,500	735,091	4.48	
13	*Lauderdale 6 CT 3*												
14	Light Oil		1,800					3,427	5,830,000	19,977	322,954	17.94	94.25
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	202	1,800	1.2%	95.5%	74.4%	11,098			19,977	322,954	17.94	
17	*Lauderdale 6 CT 4*												
18	Light Oil		1,800					3,427	5,830,000	19,977	322,954	17.94	94.25
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	202	1,800	1.2%	95.5%	74.4%	11,098			19,977	322,954	17.94	
21	*Lauderdale 6 CT 5*												
22	Light Oil		1,200					2,284	5,830,000	13,318	215,303	17.94	94.25
23	Gas		0					0	0	0	0	0.00	0.00
24	Plant Unit Info	201	1,200	0.8%	95.5%	74.7%	11,098			13,318	215,303	17.94	
25	*Manatee 1*												
26	Heavy Oil		552					1,134	6,400,000	7,260	79,637	14.44	70.20
27	Gas		12,503					164,562	1,000,000	164,562	685,635	5.48	4.17
28	Plant Unit Info	782	13,055	2.3%	96.2%	52.2%	13,161			171,822	765,272	5.86	
29	*Manatee 2*												
30	Heavy Oil		199					422	6,400,000	2,703	29,650	14.88	70.20
31	Gas		14,085					191,019	1,000,000	191,019	795,980	5.65	4.17
32	Plant Unit Info	781	14,284	2.5%	96.3%	45.7%	13,562			193,722	825,630	5.78	
33	*Manatee 3*												
34	Gas		0					0	0	0	0	0.00	0.00
35	Plant Unit Info	1,158	0	0.0%	0.0%	0.0%	0			0	0	0.00	
36	*Manatee PV Solar*												
37	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Plant Unit Info	75	0	16.6%	N/A	39.7%	N/A			0	0	0.00	
2	*Martin 1*												
3	Heavy Oil		3,204					7,023	6,400,000	44,947	512,440	15.99	72.97
4	Gas		28,072					393,823	1,000,000	393,823	1,670,603	5.95	4.24
5	Plant Unit Info	796	31,276	5.5%	96.3%	41.0%	14,029			438,770	2,183,043	6.98	
6	*Martin 2*												
7	Heavy Oil		1,174					2,680	6,400,000	17,149	195,515	16.66	72.97
8	Gas		10,136					148,089	1,000,000	148,089	627,506	6.19	4.24
9	Plant Unit Info	766	11,310	2.1%	96.3%	46.1%	14,610			165,238	823,022	7.28	
10	*Martin 3*												
11	Gas		132,196					1,111,579	1,000,000	1,111,579	4,640,854	3.51	4.18
12	Plant Unit Info	453	132,196	40.5%	94.1%	83.6%	8,409			1,111,579	4,640,854	3.51	
13	*Martin 4*												
14	Gas		4,230					41,229	1,000,000	41,229	171,734	4.06	4.17
15	Plant Unit Info	448	4,230	1.3%	9.1%	39.3%	9,747			41,229	171,734	4.06	
16	*Martin 8*												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		512,714					3,618,693	1,000,000	3,618,693	15,053,305	2.94	4.16
19	Plant Unit Info	1,007	512,714	70.7%	93.8%	70.7%	7,058			3,618,693	15,053,305	2.94	
20	*Martin 8 Solar*												
21	Solar		14,310					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	75	14,310	26.5%	N/A	48.9%	N/A			0	0	0.00	
23	*PEEC*												
24	Light Oil		4,236					4,734	5,830,000	27,600	346,520	8.18	73.20
25	Gas		792,622					5,164,876	1,000,000	5,164,876	21,893,516	2.76	4.24
26	Plant Unit Info	1,234	796,858	89.7%	93.5%	89.7%	6,516			5,192,476	22,240,036	2.79	
27	*Riviera 5*												
28	Light Oil		8,524					9,674	5,830,000	56,400	980,602	11.50	101.36
29	Gas		710,618					4,701,847	1,000,000	4,701,847	19,931,292	2.80	4.24
30	Plant Unit Info	1,241	719,142	80.5%	93.8%	80.5%	6,617			4,758,247	20,911,894	2.91	
31	*Sanford 4*												
32	Gas		177,518					1,477,767	1,000,000	1,477,767	6,265,930	3.53	4.24
33	Plant Unit Info	955	177,518	25.8%	94.1%	76.8%	8,325			1,477,767	6,265,930	3.53	
34	*Sanford 5*												
35	Gas		329,523					2,645,790	1,000,000	2,645,790	11,216,166	3.40	4.24
36	Plant Unit Info	955	329,523	47.9%	94.1%	85.2%	8,029			2,645,790	11,216,166	3.40	
37	*Scherer 4*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Coal		362,892					229,256	17,000,000	3,897,358	8,885,555	2.45	38.76
2	Plant Unit Info	598	362,892	84.3%	95.0%	84.3%	10,740			3,897,358	8,885,555	2.45	
3	*St Johns 1*												
4	Coal		38,686					19,821	22,000,000	436,072	1,458,959	3.77	73.60
5	Plant Unit Info	122	38,686	43.9%	68.1%	59.9%	11,272			436,072	1,458,959	3.77	
6	*St Johns 2*												
7	Coal		52,941					27,034	22,000,000	594,742	1,989,817	3.76	73.60
8	Plant Unit Info	122	52,941	60.1%	94.8%	60.1%	11,234			594,742	1,989,817	3.76	
9	*St Lucie 1*												
10	Nuclear		688,707					7,272,750	1,000,000	7,272,750	4,581,833	0.67	0.63
11	Plant Unit Info	981	688,707	97.5%	97.5%	97.5%	10,560			7,272,750	4,581,833	0.67	
12	*St Lucie 2*												
13	Nuclear		589,635					6,163,461	1,000,000	6,163,461	4,314,422	0.73	0.70
14	Plant Unit Info	840	589,635	97.5%	97.5%	97.5%	10,453			6,163,461	4,314,422	0.73	
15	*Space Coast*												
16	Solar		1,740					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	10	1,740	24.2%	N/A	52.7%	N/A			0	0	0.00	
18	*Turkey Point 3*												
19	Nuclear		75,910					849,656	1,000,000	849,656	518,290	0.68	0.61
20	Plant Unit Info	811	75,910	13.0%	13.0%	97.5%	11,193			849,656	518,290	0.68	
21	*Turkey Point 4*												
22	Nuclear		576,342					6,450,995	1,000,000	6,450,995	3,935,108	0.68	0.61
23	Plant Unit Info	821	576,342	97.5%	97.5%	97.5%	11,193			6,450,995	3,935,108	0.68	
24	*Turkey Point 5*												
25	Light Oil		906					1,104	5,830,000	6,434	107,936	11.91	97.80
26	Gas		582,393					4,134,810	1,000,000	4,134,810	17,526,708	3.01	4.24
27	Plant Unit Info	1,110	583,299	73.0%	94.1%	86.4%	7,100			4,141,244	17,634,644	3.02	
28	*WCEC 01*												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		717,085					4,964,889	1,000,000	4,964,889	20,614,598	2.87	4.15
31	Plant Unit Info	1,182	717,085	84.3%	94.0%	84.3%	6,924			4,964,889	20,614,598	2.87	
32	*WCEC 02*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		727,256					5,030,757	1,000,000	5,030,757	20,886,619	2.87	4.15
35	Plant Unit Info	1,172	727,256	86.2%	94.0%	86.2%	6,917			5,030,757	20,886,619	2.87	
36	*WCEC 03*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Gas		517,334					3,667,013	1,000,000	3,667,013	15,230,853	2.94	4.15
2	Plant Unit Info	1,182	517,334	60.8%	68.4%	60.8%	7,088			3,667,013	15,230,853	2.94	
3	**System Totals**												
4	Plant Unit Info	25,203	9,101,976				8,100			73,724,910	230,451,907	3	
5													
6													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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 - 2017**												
2	*Babcock PV Solar*												
3	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	75	0	19.8%	N/A	39.6%	N/A			0	0	0.00	
5	*CCEC 3*												
6	Light Oil		8,283					9,468	5,830,000	55,200	836,165	10.10	88.31
7	Gas		671,014					4,471,868	1,000,000	4,471,868	18,662,736	2.78	4.17
8	Plant Unit Info	1,223	679,297	74.7%	93.8%	74.7%	6,664			4,527,068	19,498,900	2.87	
9	*Citrus PV Solar*												
10	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75	0	19.8%	N/A	39.6%	N/A			0	0	0.00	
12	*Desoto Solar*												
13	Solar		5,766					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	25	5,766	31.0%	N/A	57.2%	N/A			0	0	0.00	
15	*Fort Myers 2*												
16	Gas		813,203					5,960,790	1,000,000	5,960,790	24,876,529	3.06	4.17
17	Plant Unit Info	1,470	813,203	74.4%	94.0%	74.4%	7,330			5,960,790	24,876,529	3.06	
18	*Fort Myers 3A*												
19	Light Oil		10					21	5,830,000	124	2,228	22.43	104.76
20	Gas		6,357					79,355	1,000,000	79,355	331,205	5.21	4.17
21	Plant Unit Info	171	6,367	5.0%	95.5%	66.4%	12,483			79,479	333,433	5.24	
22	*Fort Myers 3B*												
23	Light Oil		10					21	5,830,000	124	2,228	22.66	104.76
24	Gas		5,309					66,949	1,000,000	66,949	279,422	5.26	4.17
25	Plant Unit Info	170	5,319	4.2%	95.5%	65.3%	12,610			67,073	281,650	5.30	
26	*Fort Myers 4A*												
27	Light Oil		19					33	5,830,000	191	3,432	18.16	104.76
28	Gas		31,314					316,446	1,000,000	316,446	1,320,663	4.22	4.17
29	Plant Unit Info	223	31,333	18.9%	93.9%	77.2%	10,106			316,637	1,324,095	4.23	
30	*Fort Myers 4B*												
31	Light Oil		6					10	5,830,000	57	1,024	18.25	104.76
32	Gas		25,607					260,081	1,000,000	260,081	1,085,423	4.24	4.17
33	Plant Unit Info	223	25,613	15.4%	93.9%	76.1%	10,156			260,138	1,086,447	4.24	
34	*Lauderdale 4*												
35	Light Oil		0					0	0	0	0	0.00	0.00
36	Gas		111,805					1,003,684	1,000,000	1,003,684	4,188,766	3.75	4.17
37	Plant Unit Info	431	111,805	34.9%	93.9%	82.1%	8,977			1,003,684	4,188,766	3.75	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	*Lauderdale 5*												
2	Light Oil		0					0	0	0	0	0.00	0.00
3	Gas		60,443					572,267	1,000,000	572,267	2,388,304	3.95	4.17
4	Plant Unit Info	431	60,443	18.9%	43.9%	44.4%	9,468			572,267	2,388,304	3.95	
5	*Lauderdale 6 CT 1*												
6	Light Oil		144					257	5,830,000	1,500	24,249	16.87	94.25
7	Gas		3,142					32,794	1,000,000	32,794	136,854	4.36	4.17
8	Plant Unit Info	201	3,286	2.2%	95.5%	81.8%	10,436			34,294	161,104	4.90	
9	*Lauderdale 6 CT 2*												
10	Light Oil		515					875	5,830,000	5,100	82,448	16.02	94.25
11	Gas		20,990					207,944	1,000,000	207,944	867,875	4.13	4.17
12	Plant Unit Info	201	21,505	14.4%	95.5%	94.7%	9,907			213,044	950,323	4.42	
13	*Lauderdale 6 CT 3*												
14	Light Oil		3,600					6,853	5,830,000	39,954	645,908	17.94	94.25
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	201	3,600	2.4%	95.5%	74.7%	11,098			39,954	645,908	17.94	
17	*Lauderdale 6 CT 4*												
18	Light Oil		2,400					4,569	5,830,000	26,636	430,605	17.94	94.25
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	202	2,400	1.6%	95.5%	74.4%	11,098			26,636	430,605	17.94	
21	*Lauderdale 6 CT 5*												
22	Light Oil		0					0	0	0	0	0.00	0.00
23	Gas		0					0	0	0	0	0.00	0.00
24	Plant Unit Info	201	0	0.0%	95.5%	0.0%	0			0	0	0.00	
25	*Manatee 1*												
26	Heavy Oil		1,319					2,942	6,400,000	18,827	206,520	15.65	70.20
27	Gas		25,301					361,019	1,000,000	361,019	1,482,239	5.86	4.11
28	Plant Unit Info	781	26,620	4.6%	96.2%	40.1%	14,269			379,846	1,688,759	6.34	
29	*Manatee 2*												
30	Heavy Oil		1,402					3,112	6,400,000	19,919	218,498	15.58	70.20
31	Gas		29,431					418,028	1,000,000	418,028	1,716,338	5.83	4.11
32	Plant Unit Info	780	30,833	5.3%	96.3%	39.1%	14,204			437,947	1,934,836	6.28	
33	*Manatee 3*												
34	Gas		0					0	0	0	0	0.00	0.00
35	Plant Unit Info	1,158	0	0.0%	0.0%	0.0%	0			0	0	0.00	
36	*Manatee PV Solar*												
37	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Plant Unit Info	75	0	19.8%	N/A	39.6%	N/A			0	0	0.00	
2	*Martin 1*												
3	Heavy Oil		6,659					12,727	6,400,000	81,452	928,633	13.95	72.97
4	Gas		89,641					1,096,505	1,000,000	1,096,505	4,576,161	5.10	4.17
5	Plant Unit Info	796	96,300	16.3%	96.3%	35.9%	12,232			1,177,957	5,504,794	5.72	
6	*Martin 2*												
7	Heavy Oil		7,294					14,489	6,400,000	92,730	1,057,213	14.49	72.97
8	Gas		62,137					789,924	1,000,000	789,924	3,296,726	5.31	4.17
9	Plant Unit Info	768	69,431	12.2%	96.3%	42.6%	12,713			882,654	4,353,940	6.27	
10	*Martin 3*												
11	Gas		217,037					1,721,797	1,000,000	1,721,797	7,042,382	3.24	4.09
12	Plant Unit Info	453	217,037	64.4%	94.1%	83.5%	7,933			1,721,797	7,042,382	3.24	
13	*Martin 4*												
14	Gas		80,428					693,192	1,000,000	693,192	2,840,230	3.53	4.10
15	Plant Unit Info	447	80,428	24.2%	47.3%	44.9%	8,619			693,192	2,840,230	3.53	
16	*Martin 8*												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		624,070					4,376,496	1,000,000	4,376,496	17,883,181	2.87	4.09
19	Plant Unit Info	1,007	624,070	83.3%	93.8%	83.3%	7,013			4,376,496	17,883,181	2.87	
20	*Martin 8 Solar*												
21	Solar		14,074					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	75	14,074	25.2%	N/A	46.6%	N/A			0	0	0.00	
23	*PEEC*												
24	Light Oil		7,643					8,645	5,830,000	50,400	632,776	8.28	73.20
25	Gas		705,828					4,654,119	1,000,000	4,654,119	19,423,472	2.75	4.17
26	Plant Unit Info	1,234	713,471	77.7%	93.5%	77.7%	6,594			4,704,519	20,056,248	2.81	
27	*Riviera 5*												
28	Light Oil		7,603					8,645	5,830,000	50,400	876,283	11.53	101.36
29	Gas		695,427					4,610,162	1,000,000	4,610,162	19,240,048	2.77	4.17
30	Plant Unit Info	1,241	703,030	76.1%	93.8%	76.1%	6,629			4,660,562	20,116,331	2.86	
31	*Sanford 4*												
32	Gas		231,045					1,889,391	1,000,000	1,889,391	7,885,293	3.41	4.17
33	Plant Unit Info	955	231,045	32.5%	71.5%	70.3%	8,178			1,889,391	7,885,293	3.41	
34	*Sanford 5*												
35	Gas		413,873					3,168,788	1,000,000	3,168,788	13,224,458	3.20	4.17
36	Plant Unit Info	955	413,873	58.3%	84.4%	77.8%	7,656			3,168,788	13,224,458	3.20	
37	*Scherer 4*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Coal		359,949					228,404	17,000,000	3,882,869	8,802,107	2.45	38.54
2	Plant Unit Info	598	359,949	80.9%	95.0%	80.9%	10,787			3,882,869	8,802,107	2.45	
3	*St Johns 1*												
4	Coal		57,362					29,450	22,000,000	647,892	2,175,708	3.79	73.88
5	Plant Unit Info	122	57,362	63.0%	94.8%	63.0%	11,295			647,892	2,175,708	3.79	
6	*St Johns 2*												
7	Coal		56,179					28,825	22,000,000	634,140	2,129,526	3.79	73.88
8	Plant Unit Info	122	56,179	61.7%	94.8%	61.7%	11,288			634,140	2,129,526	3.79	
9	*St Lucie 1*												
10	Nuclear		711,664					7,515,175	1,000,000	7,515,175	4,734,560	0.67	0.63
11	Plant Unit Info	981	711,664	97.5%	97.5%	97.5%	10,560			7,515,175	4,734,560	0.67	
12	*St Lucie 2*												
13	Nuclear		609,290					6,368,910	1,000,000	6,368,910	4,458,236	0.73	0.70
14	Plant Unit Info	840	609,290	97.5%	97.5%	97.5%	10,453			6,368,910	4,458,236	0.73	
15	*Space Coast*												
16	Solar		1,891					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	10	1,891	25.4%	N/A	50.8%	N/A			0	0	0.00	
18	*Turkey Point 3*												
19	Nuclear		588,299					6,584,834	1,000,000	6,584,834	4,016,749	0.68	0.61
20	Plant Unit Info	811	588,299	97.5%	97.5%	97.5%	11,193			6,584,834	4,016,749	0.68	
21	*Turkey Point 4*												
22	Nuclear		595,553					6,666,028	1,000,000	6,666,028	4,066,278	0.68	0.61
23	Plant Unit Info	821	595,553	97.5%	97.5%	97.5%	11,193			6,666,028	4,066,278	0.68	
24	*Turkey Point 5*												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		420,595					3,107,841	1,000,000	3,107,841	12,970,264	3.08	4.17
27	Plant Unit Info	1,110	420,595	50.9%	94.1%	77.3%	7,389			3,107,841	12,970,264	3.08	
28	*WCEC 01*												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		635,501					4,481,620	1,000,000	4,481,620	18,307,482	2.88	4.09
31	Plant Unit Info	1,182	635,501	72.3%	94.0%	72.3%	7,052			4,481,620	18,307,482	2.88	
32	*WCEC 02*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		615,926					4,362,264	1,000,000	4,362,264	17,819,932	2.89	4.09
35	Plant Unit Info	1,172	615,926	70.6%	94.0%	70.6%	7,082			4,362,264	17,819,932	2.89	
36	*WCEC 03*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Gas		424,823					3,095,041	1,000,000	3,095,041	12,643,260	2.98	4.09
2	Plant Unit Info	1,182	424,823	48.3%	61.7%	48.3%	7,285			3,095,041	12,643,260	2.98	
3	**System Totals**												
4	Plant Unit Info	25,199	10,067,181				8,398			84,540,827	250,820,617	2	
5													
6													
7													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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 - 2017**												
2	*Babcock PV Solar*												
3	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	75	0	20.8%	N/A	38.4%	N/A			0	0	0.00	
5	*CCEC 3*												
6	Light Oil		9,924					11,321	5,830,000	66,000	945,035	9.52	83.48
7	Gas		696,186					4,630,103	1,000,000	4,630,103	19,028,833	2.73	4.11
8	Plant Unit Info	1,223	706,110	80.2%	93.8%	80.2%	6,651			4,696,103	19,973,867	2.83	
9	*Citrus PV Solar*												
10	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75	0	20.8%	N/A	38.4%	N/A			0	0	0.00	
12	*Desoto Solar*												
13	Solar		5,010					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	25	5,010	27.8%	N/A	51.4%	N/A			0	0	0.00	
15	*Fort Myers 2*												
16	Gas		677,564					5,054,674	1,000,000	5,054,674	20,774,039	3.07	4.11
17	Plant Unit Info	1,470	677,564	64.0%	94.0%	64.0%	7,460			5,054,674	20,774,039	3.07	
18	*Fort Myers 3A*												
19	Light Oil		0					0	0	0	0	0.00	0.00
20	Gas		0					0	0	0	0	0.00	0.00
21	Plant Unit Info	171	0	0.0%	95.5%	0.0%	0			0	0	0.00	
22	*Fort Myers 3B*												
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	170	0	0.0%	95.5%	0.0%	0			0	0	0.00	
26	*Fort Myers 4A*												
27	Light Oil		61					103	5,830,000	599	10,764	17.75	104.76
28	Gas		16,201					159,989	1,000,000	159,989	657,724	4.06	4.11
29	Plant Unit Info	223	16,262	10.1%	93.9%	86.8%	9,875			160,588	668,488	4.11	
30	*Fort Myers 4B*												
31	Light Oil		0					0	0	0	0	0.00	0.00
32	Gas		15,582					153,921	1,000,000	153,921	632,791	4.06	4.11
33	Plant Unit Info	223	15,582	9.7%	93.9%	87.3%	9,878			153,921	632,791	4.06	
34	*Lauderdale 4*												
35	Light Oil		0					0	0	0	0	0.00	0.00
36	Gas		237,316					1,872,966	1,000,000	1,872,966	7,697,551	3.24	4.11
37	Plant Unit Info	431	237,316	76.5%	93.9%	76.5%	7,892			1,872,966	7,697,551	3.24	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	*Lauderdale 5*												
2	Light Oil		0					0	0	0	0	0.00	0.00
3	Gas		237,377					1,872,585	1,000,000	1,872,585	7,696,090	3.24	4.11
4	Plant Unit Info	431	237,377	76.5%	93.9%	76.5%	7,889			1,872,585	7,696,090	3.24	
5	*Lauderdale 6 CT 1*												
6	Light Oil		0					0	0	0	0	0.00	0.00
7	Gas		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	201	0	0.0%	95.5%	0.0%	0			0	0	0.00	
9	*Lauderdale 6 CT 2*												
10	Light Oil		60					103	5,830,000	600	9,700	16.04	94.25
11	Gas		1,900					18,841	1,000,000	18,841	77,420	4.08	4.11
12	Plant Unit Info	202	1,960	1.4%	95.5%	97.2%	9,919			19,441	87,119	4.44	
13	*Lauderdale 6 CT 3*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	201	0	0.0%	95.5%	0.0%	0			0	0	0.00	
17	*Lauderdale 6 CT 4*												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	202	0	0.0%	95.5%	0.0%	0			0	0	0.00	
21	*Lauderdale 6 CT 5*												
22	Light Oil		0					0	0	0	0	0.00	0.00
23	Gas		0					0	0	0	0	0.00	0.00
24	Plant Unit Info	201	0	0.0%	95.5%	0.0%	0			0	0	0.00	
25	*Manatee 1*												
26	Heavy Oil		5,249					11,151	6,400,000	71,365	756,466	14.41	67.84
27	Gas		31,792					432,287	1,000,000	432,287	1,747,056	5.50	4.04
28	Plant Unit Info	781	37,041	6.6%	96.2%	43.9%	13,597			503,652	2,503,522	6.76	
29	*Manatee 2*												
30	Heavy Oil		4,364					9,449	6,400,000	60,472	641,001	14.69	67.84
31	Gas		23,109					320,248	1,000,000	320,248	1,295,007	5.60	4.04
32	Plant Unit Info	780	27,473	4.9%	96.3%	43.5%	13,858			380,720	1,936,008	7.05	
33	*Manatee 3*												
34	Gas		415,764					2,894,666	1,000,000	2,894,666	11,689,044	2.81	4.04
35	Plant Unit Info	1,087	415,764	53.1%	56.6%	63.7%	6,962			2,894,666	11,689,044	2.81	
36	*Manatee PV Solar*												
37	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Plant Unit Info	75	0	20.8%	N/A	38.4%	N/A			0	0	0.00	
2	*Martin 1*												
3	Heavy Oil		5,345					11,395	6,400,000	72,927	831,440	15.56	72.97
4	Gas		25,400					346,556	1,000,000	346,556	1,424,074	5.61	4.11
5	Plant Unit Info	797	30,745	5.4%	96.3%	41.9%	13,644			419,483	2,255,513	7.34	
6	*Martin 2*												
7	Heavy Oil		3,429					7,544	6,400,000	48,282	550,462	16.05	72.97
8	Gas		17,530					246,846	1,000,000	246,846	1,014,375	5.79	4.11
9	Plant Unit Info	768	20,959	3.8%	96.3%	48.7%	14,081			295,128	1,564,837	7.47	
10	*Martin 3*												
11	Gas		136,449					1,164,277	1,000,000	1,164,277	4,731,740	3.47	4.06
12	Plant Unit Info	453	136,449	41.8%	94.1%	75.9%	8,533			1,164,277	4,731,740	3.47	
13	*Martin 4*												
14	Gas		95,174					826,558	1,000,000	826,558	3,360,008	3.53	4.07
15	Plant Unit Info	447	95,174	29.6%	94.1%	73.9%	8,685			826,558	3,360,008	3.53	
16	*Martin 8*												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		551,573					3,892,606	1,000,000	3,892,606	15,698,636	2.85	4.03
19	Plant Unit Info	1,007	551,573	76.1%	93.8%	76.1%	7,057			3,892,606	15,698,636	2.85	
20	*Martin 8 Solar*												
21	Solar		13,260					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	75	13,260	24.6%	N/A	45.3%	N/A			0	0	0.00	
23	*PEEC*												
24	Light Oil		3,691					4,117	5,830,000	24,000	301,322	8.16	73.20
25	Gas		810,934					5,272,630	1,000,000	5,272,630	21,669,256	2.67	4.11
26	Plant Unit Info	1,234	814,625	91.7%	93.5%	91.7%	6,502			5,296,630	21,970,578	2.70	
27	*Riviera 5*												
28	Light Oil		9,763					11,115	5,830,000	64,800	1,126,649	11.54	101.36
29	Gas		693,858					4,605,344	1,000,000	4,605,344	18,927,052	2.73	4.11
30	Plant Unit Info	1,241	703,621	78.8%	93.8%	78.8%	6,637			4,670,144	20,053,701	2.85	
31	*Sanford 4*												
32	Gas		377,387					2,866,639	1,000,000	2,866,639	11,781,778	3.12	4.11
33	Plant Unit Info	955	377,387	54.9%	94.1%	54.9%	7,596			2,866,639	11,781,778	3.12	
34	*Sanford 5*												
35	Gas		279,646					2,125,915	1,000,000	2,125,915	8,736,908	3.12	4.11
36	Plant Unit Info	955	279,646	40.7%	45.8%	40.7%	7,602			2,125,915	8,736,908	3.12	
37	*Scherer 4*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Coal		322,845					206,467	17,000,000	3,509,946	7,953,080	2.46	38.52
2	Plant Unit Info	598	322,845	75.0%	95.0%	75.0%	10,872			3,509,946	7,953,080	2.46	
3	*St Johns 1*												
4	Coal		50,342					25,688	22,000,000	565,138	1,881,467	3.74	73.24
5	Plant Unit Info	122	50,342	57.2%	94.8%	57.2%	11,226			565,138	1,881,467	3.74	
6	*St Johns 2*												
7	Coal		49,841					25,432	22,000,000	559,505	1,862,713	3.74	73.24
8	Plant Unit Info	122	49,841	56.6%	94.8%	56.6%	11,226			559,505	1,862,713	3.74	
9	*St Lucie 1*												
10	Nuclear		688,707					7,272,750	1,000,000	7,272,750	4,581,833	0.67	0.63
11	Plant Unit Info	981	688,707	97.5%	97.5%	97.5%	10,560			7,272,750	4,581,833	0.67	
12	*St Lucie 2*												
13	Nuclear		589,635					6,163,461	1,000,000	6,163,461	4,314,422	0.73	0.70
14	Plant Unit Info	840	589,635	97.5%	97.5%	97.5%	10,453			6,163,461	4,314,422	0.73	
15	*Space Coast*												
16	Solar		1,650					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	10	1,650	22.9%	N/A	45.8%	N/A			0	0	0.00	
18	*Turkey Point 3*												
19	Nuclear		569,322					6,372,420	1,000,000	6,372,420	3,887,177	0.68	0.61
20	Plant Unit Info	811	569,322	97.5%	97.5%	97.5%	11,193			6,372,420	3,887,177	0.68	
21	*Turkey Point 4*												
22	Nuclear		576,342					6,450,995	1,000,000	6,450,995	3,935,108	0.68	0.61
23	Plant Unit Info	821	576,342	97.5%	97.5%	97.5%	11,193			6,450,995	3,935,108	0.68	
24	*Turkey Point 5*												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		532,396					3,739,878	1,000,000	3,739,878	15,370,335	2.89	4.11
27	Plant Unit Info	1,110	532,396	66.6%	94.1%	66.6%	7,025			3,739,878	15,370,335	2.89	
28	*WCEC 01*												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		575,743					4,106,418	1,000,000	4,106,418	16,505,917	2.87	4.02
31	Plant Unit Info	1,182	575,743	67.7%	94.0%	67.7%	7,132			4,106,418	16,505,917	2.87	
32	*WCEC 02*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		554,102					3,970,630	1,000,000	3,970,630	15,960,099	2.88	4.02
35	Plant Unit Info	1,172	554,102	65.7%	94.0%	65.7%	7,166			3,970,630	15,960,099	2.88	
36	*WCEC 03*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Gas		623,080					4,409,023	1,000,000	4,409,023	17,722,227	2.84	4.02
2	Plant Unit Info	1,182	623,080	73.2%	94.0%	73.2%	7,076			4,409,023	17,722,227	2.84	
3	**System Totals**												
4	Plant Unit Info	25,129	10,534,903				8,191			86,286,860	257,786,595	2	
5													
6													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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 - 2017**												
2	*Babcock PV Solar*												
3	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	75	0	18.8%	N/A	34.7%	N/A			0	0	0.00	
5	*CCEC 3*												
6	Light Oil		10,987					12,762	5,830,000	74,400	1,065,312	9.70	83.48
7	Gas		565,790					3,831,295	1,000,000	3,831,295	17,369,798	3.07	4.53
8	Plant Unit Info	1,223	576,777	63.4%	93.8%	63.4%	6,772			3,905,695	18,435,110	3.20	
9	*Citrus PV Solar*												
10	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75	0	18.8%	N/A	34.7%	N/A			0	0	0.00	
12	*Desoto Solar*												
13	Solar		4,991					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	25	4,991	26.8%	N/A	49.5%	N/A			0	0	0.00	
15	*Fort Myers 2*												
16	Gas		724,054					5,364,011	1,000,000	5,364,011	24,319,072	3.36	4.53
17	Plant Unit Info	1,470	724,054	66.2%	94.0%	66.2%	7,408			5,364,011	24,319,072	3.36	
18	*Fort Myers 3A*												
19	Light Oil		5					12	5,830,000	68	1,222	22.54	104.76
20	Gas		3,112					39,033	1,000,000	39,033	176,979	5.69	4.53
21	Plant Unit Info	171	3,117	2.5%	95.5%	65.1%	12,544			39,101	178,201	5.72	
22	*Fort Myers 3B*												
23	Light Oil		0					0	0	0	0	0.00	0.00
24	Gas		2,537					31,966	1,000,000	31,966	144,937	5.71	4.53
25	Plant Unit Info	170	2,537	2.0%	95.5%	65.0%	12,600			31,966	144,937	5.71	
26	*Fort Myers 4A*												
27	Light Oil		6					10	5,830,000	57	1,024	17.95	104.76
28	Gas		27,714					276,811	1,000,000	276,811	1,255,001	4.53	4.53
29	Plant Unit Info	223	27,720	16.7%	93.9%	82.9%	9,988			276,868	1,256,025	4.53	
30	*Fort Myers 4B*												
31	Light Oil		6					10	5,830,000	57	1,024	17.95	104.76
32	Gas		25,292					252,688	1,000,000	252,688	1,145,705	4.53	4.53
33	Plant Unit Info	223	25,298	15.3%	93.9%	83.4%	9,991			252,745	1,146,729	4.53	
34	*Lauderdale 4*												
35	Light Oil		0					0	0	0	0	0.00	0.00
36	Gas		258,496					2,024,302	1,000,000	2,024,302	9,177,636	3.55	4.53
37	Plant Unit Info	431	258,496	80.6%	93.9%	80.6%	7,831			2,024,302	9,177,636	3.55	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	*Lauderdale 5*												
2	Light Oil		0					0	0	0	0	0.00	0.00
3	Gas		261,994					2,048,035	1,000,000	2,048,035	9,285,235	3.54	4.53
4	Plant Unit Info	431	261,994	81.7%	93.9%	81.7%	7,817			2,048,035	9,285,235	3.54	
5	*Lauderdale 6 CT 1*												
6	Light Oil		86					154	5,830,000	900	14,550	17.01	94.25
7	Gas		2,091					22,003	1,000,000	22,003	99,762	4.77	4.53
8	Plant Unit Info	200	2,177	1.5%	95.5%	77.6%	10,520			22,903	114,312	5.25	
9	*Lauderdale 6 CT 2*												
10	Light Oil		300					515	5,830,000	3,000	48,499	16.16	94.25
11	Gas		11,295					112,890	1,000,000	112,890	511,852	4.53	4.53
12	Plant Unit Info	201	11,595	7.8%	95.5%	91.5%	9,995			115,890	560,351	4.83	
13	*Lauderdale 6 CT 3*												
14	Light Oil		1,950					3,699	5,830,000	21,567	348,658	17.88	94.25
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	202	1,950	1.3%	95.5%	74.4%	11,060			21,567	348,658	17.88	
17	*Lauderdale 6 CT 4*												
18	Light Oil		1,200					2,284	5,830,000	13,318	215,303	17.94	94.25
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	202	1,200	0.8%	95.5%	74.4%	11,098			13,318	215,303	17.94	
21	*Lauderdale 6 CT 5*												
22	Light Oil		0					0	0	0	0	0.00	0.00
23	Gas		0					0	0	0	0	0.00	0.00
24	Plant Unit Info	201	0	0.0%	95.5%	0.0%	0			0	0	0.00	
25	*Manatee 1*												
26	Heavy Oil		4,426					9,154	6,400,000	58,583	620,977	14.03	67.84
27	Gas		60,292					798,103	1,000,000	798,103	3,560,452	5.91	4.46
28	Plant Unit Info	781	64,718	11.1%	96.2%	45.8%	13,237			856,686	4,181,429	6.46	
29	*Manatee 2*												
30	Heavy Oil		3,092					6,549	6,400,000	41,915	444,297	14.37	67.84
31	Gas		48,771					661,176	1,000,000	661,176	2,950,645	6.05	4.46
32	Plant Unit Info	781	51,863	8.9%	96.3%	45.2%	13,557			703,091	3,394,942	6.55	
33	*Manatee 3*												
34	Gas		526,380					3,664,836	1,000,000	3,664,836	16,321,290	3.10	4.45
35	Plant Unit Info	1,087	526,380	65.1%	79.6%	65.1%	6,962			3,664,836	16,321,290	3.10	
36	*Manatee PV Solar*												
37	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Plant Unit Info	75	0	18.8%	N/A	34.7%	N/A			0	0	0.00	
2	*Martin 1*												
3	Heavy Oil		3,433					7,372	6,400,000	47,180	537,898	15.67	72.97
4	Gas		19,028					261,494	1,000,000	261,494	1,168,398	6.14	4.47
5	Plant Unit Info	797	22,461	3.8%	96.3%	44.1%	13,743			308,674	1,706,297	7.60	
6	*Martin 2*												
7	Heavy Oil		1,975					4,334	6,400,000	27,737	316,229	16.01	72.97
8	Gas		13,575					190,613	1,000,000	190,613	852,482	6.28	4.47
9	Plant Unit Info	768	15,550	2.7%	96.3%	50.6%	14,042			218,350	1,168,711	7.52	
10	*Martin 3*												
11	Gas		192,821					1,500,994	1,000,000	1,500,994	6,706,095	3.48	4.47
12	Plant Unit Info	453	192,821	57.2%	94.1%	57.2%	7,784			1,500,994	6,706,095	3.48	
13	*Martin 4*												
14	Gas		190,399					1,488,460	1,000,000	1,488,460	6,642,286	3.49	4.46
15	Plant Unit Info	447	190,399	57.3%	94.1%	57.3%	7,818			1,488,460	6,642,286	3.49	
16	*Martin 8*												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		527,765					3,718,834	1,000,000	3,718,834	16,565,241	3.14	4.45
19	Plant Unit Info	1,007	527,765	70.4%	93.8%	70.4%	7,046			3,718,834	16,565,241	3.14	
20	*Martin 8 Solar*												
21	Solar		12,679					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	75	12,679	22.7%	N/A	36.4%	N/A			0	0	0.00	
23	*PEEC*												
24	Light Oil		5,683					6,381	5,830,000	37,200	467,049	8.22	73.20
25	Gas		738,662					4,834,977	1,000,000	4,834,977	21,920,383	2.97	4.53
26	Plant Unit Info	1,234	744,345	81.1%	93.5%	81.1%	6,546			4,872,177	22,387,432	3.01	
27	*Riviera 5*												
28	Light Oil		909					1,029	5,830,000	6,000	96,080	10.57	93.36
29	Gas		765,191					5,049,505	1,000,000	5,049,505	22,562,006	2.95	4.47
30	Plant Unit Info	1,241	766,100	83.0%	93.8%	83.0%	6,599			5,055,505	22,658,086	2.96	
31	*Sanford 4*												
32	Gas		388,049					2,924,811	1,000,000	2,924,811	13,260,198	3.42	4.53
33	Plant Unit Info	955	388,049	54.6%	83.6%	54.6%	7,537			2,924,811	13,260,198	3.42	
34	*Sanford 5*												
35	Gas		336,712					2,521,323	1,000,000	2,521,323	11,431,075	3.39	4.53
36	Plant Unit Info	955	336,712	47.4%	54.6%	47.4%	7,488			2,521,323	11,431,075	3.39	
37	*Scherer 4*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Coal		376,575					237,563	17,000,000	4,038,572	9,198,620	2.44	38.72
2	Plant Unit Info	598	376,575	84.6%	95.0%	84.6%	10,724			4,038,572	9,198,620	2.44	
3	*St Johns 1*												
4	Coal		57,234					29,231	22,000,000	643,090	2,200,785	3.85	75.29
5	Plant Unit Info	122	57,234	62.9%	94.8%	62.9%	11,236			643,090	2,200,785	3.85	
6	*St Johns 2*												
7	Coal		56,008					28,581	22,000,000	628,773	2,151,789	3.84	75.29
8	Plant Unit Info	122	56,008	61.6%	94.8%	61.6%	11,227			628,773	2,151,789	3.84	
9	*St Lucie 1*												
10	Nuclear		711,664					7,515,175	1,000,000	7,515,175	4,734,560	0.67	0.63
11	Plant Unit Info	981	711,664	97.5%	97.5%	97.5%	10,560			7,515,175	4,734,560	0.67	
12	*St Lucie 2*												
13	Nuclear		609,290					6,368,910	1,000,000	6,368,910	4,458,236	0.73	0.70
14	Plant Unit Info	840	609,290	97.5%	97.5%	97.5%	10,453			6,368,910	4,458,236	0.73	
15	*Space Coast*												
16	Solar		1,798					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	10	1,798	24.2%	N/A	44.6%	N/A			0	0	0.00	
18	*Turkey Point 3*												
19	Nuclear		588,299					6,584,834	1,000,000	6,584,834	4,016,749	0.68	0.61
20	Plant Unit Info	811	588,299	97.5%	97.5%	97.5%	11,193			6,584,834	4,016,749	0.68	
21	*Turkey Point 4*												
22	Nuclear		595,553					6,666,028	1,000,000	6,666,028	4,066,278	0.68	0.61
23	Plant Unit Info	821	595,553	97.5%	97.5%	97.5%	11,193			6,666,028	4,066,278	0.68	
24	*Turkey Point 5*												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		534,208					3,735,538	1,000,000	3,735,538	16,935,874	3.17	4.53
27	Plant Unit Info	1,110	534,208	64.7%	94.1%	64.7%	6,993			3,735,538	16,935,874	3.17	
28	*WCEC 01*												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		604,904					4,306,339	1,000,000	4,306,339	19,137,041	3.16	4.44
31	Plant Unit Info	1,182	604,904	68.8%	94.0%	68.8%	7,119			4,306,339	19,137,041	3.16	
32	*WCEC 02*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		585,348					4,184,225	1,000,000	4,184,225	18,594,398	3.18	4.44
35	Plant Unit Info	1,172	585,348	67.1%	94.0%	67.1%	7,148			4,184,225	18,594,398	3.18	
36	*WCEC 03*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Gas		657,017					4,637,788	1,000,000	4,637,788	20,609,989	3.14	4.44
2	Plant Unit Info	1,182	657,017	74.7%	94.0%	74.7%	7,059			4,637,788	20,609,989	3.14	
3	**System Totals**												
4	Plant Unit Info	25,129	11,119,646				8,207			91,259,413	297,708,969	3	
5													
6													
7													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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 - 2017**												
2	*Babcock PV Solar*												
3	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	75	0	17.9%	N/A	33.0%	N/A			0	0	0.00	
5	*CCEC 3*												
6	Light Oil		11,066					12,762	5,830,000	74,400	1,027,874	9.29	80.54
7	Gas		622,908					4,187,819	1,000,000	4,187,819	18,885,135	3.03	4.51
8	Plant Unit Info	1,223	633,974	69.7%	93.8%	69.7%	6,723			4,262,219	19,913,010	3.14	
9	*Citrus PV Solar*												
10	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75	0	17.9%	N/A	33.0%	N/A			0	0	0.00	
12	*Desoto Solar*												
13	Solar		4,712					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	25	4,712	25.3%	N/A	46.8%	N/A			0	0	0.00	
15	*Fort Myers 2*												
16	Gas		714,581					5,306,857	1,000,000	5,306,857	23,931,432	3.35	4.51
17	Plant Unit Info	1,470	714,581	65.3%	94.0%	65.3%	7,427			5,306,857	23,931,432	3.35	
18	*Fort Myers 3A*												
19	Light Oil		0					0	0	0	0	0.00	0.00
20	Gas		1,387					17,287	1,000,000	17,287	77,959	5.62	4.51
21	Plant Unit Info	171	1,387	1.1%	95.5%	67.6%	12,464			17,287	77,959	5.62	
22	*Fort Myers 3B*												
23	Light Oil		0					0	0	0	0	0.00	0.00
24	Gas		2,349					29,074	1,000,000	29,074	131,113	5.58	4.51
25	Plant Unit Info	170	2,349	1.9%	95.5%	69.2%	12,377			29,074	131,113	5.58	
26	*Fort Myers 4A*												
27	Light Oil		0					0	0	0	0	0.00	0.00
28	Gas		20,724					204,510	1,000,000	204,510	922,234	4.45	4.51
29	Plant Unit Info	223	20,724	12.5%	93.9%	90.2%	9,868			204,510	922,234	4.45	
30	*Fort Myers 4B*												
31	Light Oil		0					0	0	0	0	0.00	0.00
32	Gas		15,500					153,450	1,000,000	153,450	691,977	4.46	4.51
33	Plant Unit Info	223	15,500	9.3%	93.9%	89.1%	9,900			153,450	691,977	4.46	
34	*Lauderdale 4*												
35	Light Oil		0					0	0	0	0	0.00	0.00
36	Gas		260,654					2,039,087	1,000,000	2,039,087	9,195,328	3.53	4.51
37	Plant Unit Info	431	260,654	81.3%	93.9%	81.3%	7,823			2,039,087	9,195,328	3.53	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	*Lauderdale 5*												
2	Light Oil		0					0	0	0	0	0.00	0.00
3	Gas		261,973					2,048,028	1,000,000	2,048,028	9,235,648	3.53	4.51
4	Plant Unit Info	431	261,973	81.7%	93.9%	81.7%	7,818			2,048,028	9,235,648	3.53	
5	*Lauderdale 6 CT 1*												
6	Light Oil		115					206	5,830,000	1,200	19,400	16.92	94.25
7	Gas		2,484					26,007	1,000,000	26,007	117,281	4.72	4.51
8	Plant Unit Info	201	2,599	1.7%	95.5%	80.9%	10,468			27,207	136,681	5.26	
9	*Lauderdale 6 CT 2*												
10	Light Oil		209					360	5,830,000	2,100	33,949	16.21	94.25
11	Gas		5,533					55,460	1,000,000	55,460	250,103	4.52	4.51
12	Plant Unit Info	201	5,742	3.8%	95.5%	95.2%	10,024			57,560	284,053	4.95	
13	*Lauderdale 6 CT 3*												
14	Light Oil		1,200					2,284	5,830,000	13,318	215,303	17.94	94.25
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	202	1,200	0.8%	95.5%	74.4%	11,098			13,318	215,303	17.94	
17	*Lauderdale 6 CT 4*												
18	Light Oil		600					1,142	5,830,000	6,659	107,651	17.94	94.25
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	202	600	0.4%	95.5%	74.4%	11,098			6,659	107,651	17.94	
21	*Lauderdale 6 CT 5*												
22	Light Oil		0					0	0	0	0	0.00	0.00
23	Gas		0					0	0	0	0	0.00	0.00
24	Plant Unit Info	201	0	0.0%	95.5%	0.0%	0			0	0	0.00	
25	*Manatee 1*												
26	Heavy Oil		6,552					13,153	6,400,000	84,179	892,294	13.62	67.84
27	Gas		74,530					957,618	1,000,000	957,618	4,247,551	5.70	4.44
28	Plant Unit Info	781	81,082	14.0%	96.2%	50.4%	12,849			1,041,797	5,139,845	6.34	
29	*Manatee 2*												
30	Heavy Oil		4,144					8,437	6,400,000	53,997	572,366	13.81	67.84
31	Gas		60,566					789,166	1,000,000	789,166	3,501,019	5.78	4.44
32	Plant Unit Info	781	64,710	11.1%	96.3%	49.9%	13,030			843,163	4,073,384	6.29	
33	*Manatee 3*												
34	Gas		576,720					4,027,663	1,000,000	4,027,663	17,855,393	3.10	4.43
35	Plant Unit Info	1,087	576,720	71.3%	94.1%	71.3%	6,984			4,027,663	17,855,393	3.10	
36	*Manatee PV Solar*												
37	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Plant Unit Info	75	0	17.9%	N/A	33.0%	N/A			0	0	0.00	
2	*Martin 1*												
3	Heavy Oil		6,722					14,052	6,400,000	89,935	1,025,348	15.25	72.97
4	Gas		36,868					493,227	1,000,000	493,227	2,191,669	5.94	4.44
5	Plant Unit Info	796	43,590	7.4%	96.3%	43.8%	13,378			583,162	3,217,016	7.38	
6	*Martin 2*												
7	Heavy Oil		4,279					9,141	6,400,000	58,501	666,969	15.59	72.97
8	Gas		19,412					265,388	1,000,000	265,388	1,179,259	6.07	4.44
9	Plant Unit Info	767	23,691	4.2%	96.3%	55.1%	13,671			323,889	1,846,228	7.79	
10	*Martin 3*												
11	Gas		199,741					1,554,216	1,000,000	1,554,216	6,910,577	3.46	4.45
12	Plant Unit Info	453	199,741	59.3%	94.1%	59.3%	7,781			1,554,216	6,910,577	3.46	
13	*Martin 4*												
14	Gas		195,761					1,525,272	1,000,000	1,525,272	6,774,917	3.46	4.44
15	Plant Unit Info	447	195,761	58.9%	94.1%	58.9%	7,792			1,525,272	6,774,917	3.46	
16	*Martin 8*												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		513,772					3,619,519	1,000,000	3,619,519	16,045,666	3.12	4.43
19	Plant Unit Info	1,007	513,772	68.6%	93.8%	68.6%	7,045			3,619,519	16,045,666	3.12	
20	*Martin 8 Solar*												
21	Solar		11,873					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	75	11,873	21.3%	N/A	39.3%	N/A			0	0	0.00	
23	*PEEC*												
24	Light Oil		3,871					4,322	5,830,000	25,200	316,388	8.17	73.20
25	Gas		809,378					5,268,559	1,000,000	5,268,559	23,758,771	2.94	4.51
26	Plant Unit Info	1,234	813,249	88.6%	93.5%	88.6%	6,509			5,293,759	24,075,159	2.96	
27	*Riviera 5*												
28	Light Oil		1,169					1,324	5,830,000	7,718	123,591	10.57	93.36
29	Gas		767,152					5,062,859	1,000,000	5,062,859	22,496,965	2.93	4.44
30	Plant Unit Info	1,241	768,321	83.2%	93.8%	83.2%	6,600			5,070,577	22,620,556	2.94	
31	*Sanford 4*												
32	Gas		301,769					2,269,235	1,000,000	2,269,235	10,233,189	3.39	4.51
33	Plant Unit Info	955	301,769	42.5%	44.1%	42.5%	7,520			2,269,235	10,233,189	3.39	
34	*Sanford 5*												
35	Gas		428,657					3,219,255	1,000,000	3,219,255	14,517,376	3.39	4.51
36	Plant Unit Info	955	428,657	60.3%	93.3%	60.3%	7,510			3,219,255	14,517,376	3.39	
37	*Scherer 4*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Coal		368,227					232,704	17,000,000	3,955,974	9,073,582	2.46	38.99
2	Plant Unit Info	598	368,227	82.8%	95.0%	82.8%	10,743			3,955,974	9,073,582	2.46	
3	*St Johns 1*												
4	Coal		59,268					30,341	22,000,000	667,513	2,328,773	3.93	76.75
5	Plant Unit Info	122	59,268	65.1%	94.8%	65.1%	11,263			667,513	2,328,773	3.93	
6	*St Johns 2*												
7	Coal		58,126					29,742	22,000,000	654,319	2,282,743	3.93	76.75
8	Plant Unit Info	122	58,126	63.9%	94.8%	63.9%	11,257			654,319	2,282,743	3.93	
9	*St Lucie 1*												
10	Nuclear		711,664					7,515,175	1,000,000	7,515,175	4,734,560	0.67	0.63
11	Plant Unit Info	981	711,664	97.5%	97.5%	97.5%	10,560			7,515,175	4,734,560	0.67	
12	*St Lucie 2*												
13	Nuclear		609,290					6,368,910	1,000,000	6,368,910	4,458,236	0.73	0.70
14	Plant Unit Info	840	609,290	97.5%	97.5%	97.5%	10,453			6,368,910	4,458,236	0.73	
15	*Space Coast*												
16	Solar		1,674					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	10	1,674	22.5%	N/A	49.1%	N/A			0	0	0.00	
18	*Turkey Point 3*												
19	Nuclear		588,299					6,584,834	1,000,000	6,584,834	4,016,749	0.68	0.61
20	Plant Unit Info	811	588,299	97.5%	97.5%	97.5%	11,193			6,584,834	4,016,749	0.68	
21	*Turkey Point 4*												
22	Nuclear		595,553					6,666,028	1,000,000	6,666,028	4,066,278	0.68	0.61
23	Plant Unit Info	821	595,553	97.5%	97.5%	97.5%	11,193			6,666,028	4,066,278	0.68	
24	*Turkey Point 5*												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		550,458					3,845,885	1,000,000	3,845,885	17,343,128	3.15	4.51
27	Plant Unit Info	1,110	550,458	66.7%	94.1%	66.7%	6,987			3,845,885	17,343,128	3.15	
28	*WCEC 01*												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		597,778					4,261,332	1,000,000	4,261,332	18,832,676	3.15	4.42
31	Plant Unit Info	1,182	597,778	68.0%	94.0%	68.0%	7,129			4,261,332	18,832,676	3.15	
32	*WCEC 02*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		578,115					4,138,338	1,000,000	4,138,338	18,289,117	3.16	4.42
35	Plant Unit Info	1,172	578,115	66.3%	94.0%	66.3%	7,158			4,138,338	18,289,117	3.16	
36	*WCEC 03*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Gas		649,325					4,590,529	1,000,000	4,590,529	20,287,541	3.12	4.42
2	Plant Unit Info	1,182	649,325	73.8%	94.0%	73.8%	7,070			4,590,529	20,287,541	3.12	
3	**System Totals**												
4	Plant Unit Info	25,129	11,316,708				8,199			92,785,599	303,865,076	3	
5													
6													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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 - 2017**												
2	*Babcock PV Solar*												
3	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	75	0	16.9%	N/A	31.2%	N/A			0	0	0.00	
5	*CCEC 3*												
6	Light Oil		10,619					12,350	5,830,000	72,000	994,717	9.37	80.54
7	Gas		538,265					3,649,760	1,000,000	3,649,760	16,639,030	3.09	4.56
8	Plant Unit Info	1,223	548,884	62.3%	93.8%	62.3%	6,781			3,721,760	17,633,746	3.21	
9	*Citrus PV Solar*												
10	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75	0	16.9%	N/A	31.2%	N/A			0	0	0.00	
12	*Desoto Solar*												
13	Solar		4,230					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	25	4,230	23.5%	N/A	51.3%	N/A			0	0	0.00	
15	*Fort Myers 2*												
16	Gas		719,259					5,319,383	1,000,000	5,319,383	24,250,971	3.37	4.56
17	Plant Unit Info	1,470	719,259	68.0%	94.0%	68.0%	7,396			5,319,383	24,250,971	3.37	
18	*Fort Myers 3A*												
19	Light Oil		0					0	0	0	0	0.00	0.00
20	Gas		2,406					30,506	1,000,000	30,506	139,070	5.78	4.56
21	Plant Unit Info	171	2,406	2.0%	95.5%	63.8%	12,679			30,506	139,070	5.78	
22	*Fort Myers 3B*												
23	Light Oil		0					0	0	0	0	0.00	0.00
24	Gas		3,386					42,418	1,000,000	42,418	193,412	5.71	4.56
25	Plant Unit Info	170	3,386	2.8%	95.5%	66.5%	12,527			42,418	193,412	5.71	
26	*Fort Myers 4A*												
27	Light Oil		0					0	0	0	0	0.00	0.00
28	Gas		19,509					196,024	1,000,000	196,024	893,665	4.58	4.56
29	Plant Unit Info	223	19,509	12.2%	93.9%	81.8%	10,048			196,024	893,665	4.58	
30	*Fort Myers 4B*												
31	Light Oil		0					0	0	0	0	0.00	0.00
32	Gas		18,304					184,554	1,000,000	184,554	841,373	4.60	4.56
33	Plant Unit Info	223	18,304	11.4%	93.9%	81.3%	10,083			184,554	841,373	4.60	
34	*Lauderdale 4*												
35	Light Oil		0					0	0	0	0	0.00	0.00
36	Gas		251,999					1,970,707	1,000,000	1,970,707	8,984,343	3.57	4.56
37	Plant Unit Info	431	251,999	81.2%	93.9%	81.2%	7,820			1,970,707	8,984,343	3.57	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	*Lauderdale 5*												
2	Light Oil		0					0	0	0	0	0.00	0.00
3	Gas		255,425					1,993,711	1,000,000	1,993,711	9,089,215	3.56	4.56
4	Plant Unit Info	431	255,425	82.3%	93.9%	82.3%	7,805			1,993,711	9,089,215	3.56	
5	*Lauderdale 6 CT 1*												
6	Light Oil		143					257	5,830,000	1,500	24,249	17.01	94.25
7	Gas		3,303					34,768	1,000,000	34,768	158,539	4.80	4.56
8	Plant Unit Info	201	3,446	2.4%	95.5%	77.9%	10,525			36,268	182,788	5.30	
9	*Lauderdale 6 CT 2*												
10	Light Oil		240					412	5,830,000	2,400	38,799	16.13	94.25
11	Gas		8,705					86,870	1,000,000	86,870	396,065	4.55	4.56
12	Plant Unit Info	201	8,945	6.2%	95.5%	92.7%	9,980			89,270	434,864	4.86	
13	*Lauderdale 6 CT 3*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	202	0	0.0%	95.5%	0.0%	0			0	0	0.00	
17	*Lauderdale 6 CT 4*												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	202	0	0.0%	95.5%	0.0%	0			0	0	0.00	
21	*Lauderdale 6 CT 5*												
22	Light Oil		0					0	0	0	0	0.00	0.00
23	Gas		0					0	0	0	0	0.00	0.00
24	Plant Unit Info	201	0	0.0%	95.5%	0.0%	0			0	0	0.00	
25	*Manatee 1*												
26	Heavy Oil		2,951					6,347	6,400,000	40,621	430,581	14.59	67.84
27	Gas		53,573					737,546	1,000,000	737,546	3,310,446	6.18	4.49
28	Plant Unit Info	781	56,524	10.1%	96.2%	42.6%	13,767			778,167	3,741,027	6.62	
29	*Manatee 2*												
30	Heavy Oil		1,119					2,454	6,400,000	15,708	166,504	14.88	67.84
31	Gas		38,171					535,736	1,000,000	535,736	2,405,043	6.30	4.49
32	Plant Unit Info	781	39,290	7.0%	96.3%	41.6%	14,035			551,444	2,571,547	6.55	
33	*Manatee 3*												
34	Gas		566,642					3,951,244	1,000,000	3,951,244	17,692,543	3.12	4.48
35	Plant Unit Info	1,087	566,642	72.4%	94.1%	72.4%	6,973			3,951,244	17,692,543	3.12	
36	*Manatee PV Solar*												
37	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Plant Unit Info	75	0	16.9%	N/A	31.2%	N/A			0	0	0.00	
2	*Martin 1*												
3	Heavy Oil		2,525					5,545	6,400,000	35,488	404,598	16.03	72.97
4	Gas		21,259					298,828	1,000,000	298,828	1,342,614	6.32	4.49
5	Plant Unit Info	796	23,784	4.2%	96.3%	38.3%	14,056			334,316	1,747,213	7.35	
6	*Martin 2*												
7	Heavy Oil		0					0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	767	0	0.0%	96.3%	0.0%	0			0	0	0.00	
10	*Martin 3*												
11	Gas		109,628					933,048	1,000,000	933,048	4,196,445	3.83	4.50
12	Plant Unit Info	453	109,628	33.6%	94.1%	80.4%	8,511			933,048	4,196,445	3.83	
13	*Martin 4*												
14	Gas		99,572					853,402	1,000,000	853,402	3,835,963	3.85	4.49
15	Plant Unit Info	447	99,572	30.9%	94.1%	78.2%	8,571			853,402	3,835,963	3.85	
16	*Martin 8*												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		498,884					3,507,905	1,000,000	3,507,905	15,710,256	3.15	4.48
19	Plant Unit Info	1,007	498,884	68.8%	93.8%	68.8%	7,032			3,507,905	15,710,256	3.15	
20	*Martin 8 Solar*												
21	Solar		10,320					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	75	10,320	19.1%	N/A	35.3%	N/A			0	0	0.00	
23	*PEEC*												
24	Light Oil		5,145					5,763	5,830,000	33,600	421,851	8.20	73.20
25	Gas		750,414					4,900,652	1,000,000	4,900,652	22,341,715	2.98	4.56
26	Plant Unit Info	1,234	755,559	85.0%	93.5%	85.0%	6,531			4,934,252	22,763,566	3.01	
27	*Riviera 5*												
28	Light Oil		36					41	5,830,000	238	3,811	10.58	93.36
29	Gas		733,584					4,847,807	1,000,000	4,847,807	21,780,851	2.97	4.49
30	Plant Unit Info	1,241	733,620	82.1%	93.8%	82.1%	6,608			4,848,045	21,784,662	2.97	
31	*Sanford 4*												
32	Gas		330,560					2,482,663	1,000,000	2,482,663	11,318,253	3.42	4.56
33	Plant Unit Info	955	330,560	48.1%	56.6%	48.1%	7,510			2,482,663	11,318,253	3.42	
34	*Sanford 5*												
35	Gas		426,217					3,194,127	1,000,000	3,194,127	14,562,071	3.42	4.56
36	Plant Unit Info	955	426,217	62.0%	94.1%	62.0%	7,494			3,194,127	14,562,071	3.42	
37	*Scherer 4*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Coal		359,774					227,199	17,000,000	3,862,384	8,875,625	2.47	39.07
2	Plant Unit Info	598	359,774	83.5%	95.0%	83.5%	10,736			3,862,384	8,875,625	2.47	
3	*St Johns 1*												
4	Coal		54,420					27,757	22,000,000	610,660	2,159,535	3.97	77.80
5	Plant Unit Info	122	54,420	61.8%	94.8%	61.8%	11,221			610,660	2,159,535	3.97	
6	*St Johns 2*												
7	Coal		53,580					27,307	22,000,000	600,762	2,124,529	3.97	77.80
8	Plant Unit Info	122	53,580	60.9%	94.8%	60.9%	11,212			600,762	2,124,529	3.97	
9	*St Lucie 1*												
10	Nuclear		688,707					7,272,750	1,000,000	7,272,750	4,581,833	0.67	0.63
11	Plant Unit Info	981	688,707	97.5%	97.5%	97.5%	10,560			7,272,750	4,581,833	0.67	
12	*St Lucie 2*												
13	Nuclear		589,635					6,163,461	1,000,000	6,163,461	4,314,422	0.73	0.70
14	Plant Unit Info	840	589,635	97.5%	97.5%	97.5%	10,453			6,163,461	4,314,422	0.73	
15	*Space Coast*												
16	Solar		1,440					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	10	1,440	20.0%	N/A	43.6%	N/A			0	0	0.00	
18	*Turkey Point 3*												
19	Nuclear		569,322					6,372,420	1,000,000	6,372,420	3,887,177	0.68	0.61
20	Plant Unit Info	811	569,322	97.5%	97.5%	97.5%	11,193			6,372,420	3,887,177	0.68	
21	*Turkey Point 4*												
22	Nuclear		576,342					6,450,995	1,000,000	6,450,995	3,935,108	0.68	0.61
23	Plant Unit Info	821	576,342	97.5%	97.5%	97.5%	11,193			6,450,995	3,935,108	0.68	
24	*Turkey Point 5*												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		448,758					3,130,554	1,000,000	3,130,554	14,272,146	3.18	4.56
27	Plant Unit Info	1,110	448,758	56.2%	69.1%	56.2%	6,976			3,130,554	14,272,146	3.18	
28	*WCEC 01*												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		566,386					4,046,848	1,000,000	4,046,848	18,086,264	3.19	4.47
31	Plant Unit Info	1,182	566,386	66.6%	94.0%	66.6%	7,145			4,046,848	18,086,264	3.19	
32	*WCEC 02*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		549,679					3,942,859	1,000,000	3,942,859	17,621,524	3.21	4.47
35	Plant Unit Info	1,172	549,679	65.1%	94.0%	65.1%	7,173			3,942,859	17,621,524	3.21	
36	*WCEC 03*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Gas		619,953					4,388,955	1,000,000	4,388,955	19,615,164	3.16	4.47
2	Plant Unit Info	1,182	619,953	72.9%	94.0%	72.9%	7,079			4,388,955	19,615,164	3.16	
3	**System Totals**												
4	Plant Unit Info	25,129	10,564,389				8,216			86,795,862	282,040,317	3	
5													
6													
7													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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 - 2017**												
2	*Babcock PV Solar*												
3	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	75	0	15.7%	N/A	34.2%	N/A			0	0	0.00	
5	*CCEC 3*												
6	Light Oil		10,814					12,556	5,830,000	73,200	1,011,296	9.35	80.54
7	Gas		566,673					3,835,889	1,000,000	3,835,889	17,525,728	3.09	4.57
8	Plant Unit Info	1,223	577,487	63.5%	93.8%	63.5%	6,769			3,909,089	18,537,023	3.21	
9	*Citrus PV Solar*												
10	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75	0	15.7%	N/A	34.2%	N/A			0	0	0.00	
12	*Desoto Solar*												
13	Solar		4,061					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	25	4,061	21.8%	N/A	47.6%	N/A			0	0	0.00	
15	*Fort Myers 2*												
16	Gas		869,177					6,290,610	1,000,000	6,290,610	28,740,942	3.31	4.57
17	Plant Unit Info	1,470	869,177	79.5%	94.0%	79.5%	7,237			6,290,610	28,740,942	3.31	
18	*Fort Myers 3A*												
19	Light Oil		0					0	0	0	0	0.00	0.00
20	Gas		2,561					31,648	1,000,000	31,648	144,603	5.65	4.57
21	Plant Unit Info	171	2,561	2.0%	95.5%	68.0%	12,358			31,648	144,603	5.65	
22	*Fort Myers 3B*												
23	Light Oil		0					0	0	0	0	0.00	0.00
24	Gas		1,997					25,125	1,000,000	25,125	114,797	5.75	4.57
25	Plant Unit Info	170	1,997	1.6%	95.5%	65.3%	12,581			25,125	114,797	5.75	
26	*Fort Myers 4A*												
27	Light Oil		0					0	0	0	0	0.00	0.00
28	Gas		18,339					186,094	1,000,000	186,094	850,238	4.64	4.57
29	Plant Unit Info	223	18,339	11.1%	93.9%	76.8%	10,147			186,094	850,238	4.64	
30	*Fort Myers 4B*												
31	Light Oil		0					0	0	0	0	0.00	0.00
32	Gas		16,501					168,238	1,000,000	168,238	768,652	4.66	4.57
33	Plant Unit Info	223	16,501	10.0%	93.9%	76.3%	10,196			168,238	768,652	4.66	
34	*Lauderdale 4*												
35	Light Oil		0					0	0	0	0	0.00	0.00
36	Gas		60,002					536,626	1,000,000	536,626	2,451,698	4.09	4.57
37	Plant Unit Info	431	60,002	18.7%	93.9%	76.9%	8,943			536,626	2,451,698	4.09	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	*Lauderdale 5*												
2	Light Oil		0					0	0	0	0	0.00	0.00
3	Gas		82,145					736,306	1,000,000	736,306	3,364,039	4.10	4.57
4	Plant Unit Info	431	82,145	25.6%	93.9%	79.4%	8,963			736,306	3,364,039	4.10	
5	*Lauderdale 6 CT 1*												
6	Light Oil		198					360	5,830,000	2,100	32,424	16.35	90.02
7	Gas		5,067					53,644	1,000,000	53,644	245,101	4.84	4.57
8	Plant Unit Info	201	5,265	3.5%	95.5%	74.8%	10,588			55,744	277,526	5.27	
9	*Lauderdale 6 CT 2*												
10	Light Oil		271					463	5,830,000	2,700	41,688	15.37	90.02
11	Gas		11,387					113,380	1,000,000	113,380	517,998	4.55	4.57
12	Plant Unit Info	201	11,658	7.8%	95.5%	92.1%	9,957			116,080	559,686	4.80	
13	*Lauderdale 6 CT 3*												
14	Light Oil		1,950					3,699	5,830,000	21,567	332,997	17.08	90.02
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	202	1,950	1.3%	95.5%	74.4%	11,060			21,567	332,997	17.08	
17	*Lauderdale 6 CT 4*												
18	Light Oil		1,800					3,427	5,830,000	19,977	308,447	17.14	90.02
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	202	1,800	1.2%	95.5%	74.4%	11,098			19,977	308,447	17.14	
21	*Lauderdale 6 CT 5*												
22	Light Oil		1,800					3,427	5,830,000	19,977	308,447	17.14	90.02
23	Gas		0					0	0	0	0	0.00	0.00
24	Plant Unit Info	202	1,800	1.2%	95.5%	74.4%	11,098			19,977	308,447	17.14	
25	*Manatee 1*												
26	Heavy Oil		1,173					2,423	6,400,000	15,508	164,384	14.01	67.84
27	Gas		46,227					611,108	1,000,000	611,108	2,747,783	5.94	4.50
28	Plant Unit Info	781	47,400	8.2%	96.2%	37.5%	13,220			626,616	2,912,167	6.14	
29	*Manatee 2*												
30	Heavy Oil		1,192					2,448	6,400,000	15,667	166,070	13.93	67.84
31	Gas		42,059					552,796	1,000,000	552,796	2,485,283	5.91	4.50
32	Plant Unit Info	781	43,251	7.4%	96.3%	36.2%	13,143			568,463	2,651,352	6.13	
33	*Manatee 3*												
34	Gas		698,267					4,854,132	1,000,000	4,854,132	21,784,999	3.12	4.49
35	Plant Unit Info	1,087	698,267	86.3%	94.1%	91.6%	6,952			4,854,132	21,784,999	3.12	
36	*Manatee PV Solar*												
37	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Plant Unit Info	75	0	15.7%	N/A	34.2%	N/A			0	0	0.00	
2	*Martin 1*												
3	Heavy Oil		2,456					5,616	6,400,000	35,944	409,797	16.68	72.97
4	Gas		24,271					355,145	1,000,000	355,145	1,601,773	6.60	4.51
5	Plant Unit Info	797	26,727	4.5%	96.3%	30.8%	14,633			391,089	2,011,570	7.53	
6	*Martin 2*												
7	Heavy Oil		710					1,719	6,400,000	11,004	125,456	17.67	72.97
8	Gas		7,094					109,970	1,000,000	109,970	495,986	6.99	4.51
9	Plant Unit Info	766	7,804	1.4%	96.3%	40.8%	15,501			120,974	621,442	7.96	
10	*Martin 3*												
11	Gas		229,974					1,748,522	1,000,000	1,748,522	7,875,880	3.42	4.50
12	Plant Unit Info	453	229,974	68.2%	94.1%	89.7%	7,603			1,748,522	7,875,880	3.42	
13	*Martin 4*												
14	Gas		205,145					1,569,608	1,000,000	1,569,608	7,065,629	3.44	4.50
15	Plant Unit Info	447	205,145	61.7%	94.1%	83.0%	7,651			1,569,608	7,065,629	3.44	
16	*Martin 8*												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		575,423					4,062,797	1,000,000	4,062,797	18,257,900	3.17	4.49
19	Plant Unit Info	1,007	575,423	76.8%	93.8%	76.8%	7,061			4,062,797	18,257,900	3.17	
20	*Martin 8 Solar*												
21	Solar		9,114					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	75	9,114	16.3%	N/A	30.1%	N/A			0	0	0.00	
23	*PEEC*												
24	Light Oil		7,865					9,057	5,830,000	52,800	651,974	8.29	71.99
25	Gas		529,120					3,552,073	1,000,000	3,552,073	16,228,925	3.07	4.57
26	Plant Unit Info	1,234	536,985	58.5%	78.5%	58.5%	6,713			3,604,873	16,880,899	3.14	
27	*Riviera 5*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		720,639					4,741,405	1,000,000	4,741,405	21,384,653	2.97	4.51
30	Plant Unit Info	1,241	720,639	78.1%	93.8%	78.1%	6,579			4,741,405	21,384,653	2.97	
31	*Sanford 4*												
32	Gas		393,998					3,087,869	1,000,000	3,087,869	14,107,955	3.58	4.57
33	Plant Unit Info	955	393,998	55.5%	94.1%	80.9%	7,837			3,087,869	14,107,955	3.58	
34	*Sanford 5*												
35	Gas		460,577					3,469,073	1,000,000	3,469,073	15,849,567	3.44	4.57
36	Plant Unit Info	955	460,577	64.8%	94.1%	83.7%	7,532			3,469,073	15,849,567	3.44	
37	*Scherer 4*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Coal		393,955					247,637	17,000,000	4,209,836	9,679,285	2.46	39.09
2	Plant Unit Info	598	393,955	88.5%	95.0%	88.5%	10,686			4,209,836	9,679,285	2.46	
3	*St Johns 1*												
4	Coal		62,127					31,861	22,000,000	700,941	2,501,520	4.03	78.51
5	Plant Unit Info	122	62,127	68.3%	94.8%	68.3%	11,282			700,941	2,501,520	4.03	
6	*St Johns 2*												
7	Coal		60,378					30,900	22,000,000	679,793	2,426,048	4.02	78.51
8	Plant Unit Info	122	60,378	66.4%	94.8%	66.4%	11,259			679,793	2,426,048	4.02	
9	*St Lucie 1*												
10	Nuclear		711,664					7,515,175	1,000,000	7,515,175	4,734,560	0.67	0.63
11	Plant Unit Info	981	711,664	97.5%	97.5%	97.5%	10,560			7,515,175	4,734,560	0.67	
12	*St Lucie 2*												
13	Nuclear		609,290					6,368,910	1,000,000	6,368,910	4,458,236	0.73	0.70
14	Plant Unit Info	840	609,290	97.5%	97.5%	97.5%	10,453			6,368,910	4,458,236	0.73	
15	*Space Coast*												
16	Solar		1,395					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	10	1,395	18.8%	N/A	45.0%	N/A			0	0	0.00	
18	*Turkey Point 3*												
19	Nuclear		588,299					6,584,834	1,000,000	6,584,834	4,016,749	0.68	0.61
20	Plant Unit Info	811	588,299	97.5%	97.5%	97.5%	11,193			6,584,834	4,016,749	0.68	
21	*Turkey Point 4*												
22	Nuclear		19,211					215,033	1,000,000	215,033	131,170	0.68	0.61
23	Plant Unit Info	820	19,211	3.2%	3.2%	97.7%	11,193			215,033	131,170	0.68	
24	*Turkey Point 5*												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		168,358					1,299,604	1,000,000	1,299,604	5,937,962	3.53	4.57
27	Plant Unit Info	1,110	168,358	20.4%	37.7%	45.4%	7,719			1,299,604	5,937,962	3.53	
28	*WCEC 01*												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		575,672					4,117,828	1,000,000	4,117,828	18,457,413	3.21	4.48
31	Plant Unit Info	1,182	575,672	65.5%	94.0%	65.5%	7,153			4,117,828	18,457,413	3.21	
32	*WCEC 02*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		574,294					4,111,175	1,000,000	4,111,175	18,427,566	3.21	4.48
35	Plant Unit Info	1,172	574,294	65.9%	94.0%	65.9%	7,159			4,111,175	18,427,566	3.21	
36	*WCEC 03*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Gas		520,970					3,746,746	1,000,000	3,746,746	16,793,987	3.22	4.48
2	Plant Unit Info	1,182	520,970	59.2%	79.0%	59.2%	7,192			3,746,746	16,793,987	3.22	
3	**System Totals**												
4	Plant Unit Info	25,127	9,895,660				8,136			80,512,376	275,727,606	3	
5													
6													
7													
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10													
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FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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 - 2017**												
2	*Babcock PV Solar*												
3	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	75	0	14.7%	N/A	32.0%	N/A			0	0	0.00	
5	*CCEC 3*												
6	Light Oil		7,435					8,645	5,830,000	50,400	671,427	9.03	77.67
7	Gas		464,464					3,148,289	1,000,000	3,148,289	15,987,708	3.44	5.08
8	Plant Unit Info	1,234	471,899	53.1%	73.8%	53.1%	6,778			3,198,689	16,659,135	3.53	
9	*Citrus PV Solar*												
10	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75	0	14.7%	N/A	32.0%	N/A			0	0	0.00	
12	*Desoto Solar*												
13	Solar		3,480					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	25	3,480	19.3%	N/A	46.4%	N/A			0	0	0.00	
15	*Fort Myers 2*												
16	Gas		734,114					5,433,048	1,000,000	5,433,048	27,590,094	3.76	5.08
17	Plant Unit Info	1,669	734,114	50.7%	50.7%	61.1%	7,401			5,433,048	27,590,094	3.76	
18	*Fort Myers 3A*												
19	Light Oil		0					0	0	0	0	0.00	0.00
20	Gas		0					0	0	0	0	0.00	0.00
21	Plant Unit Info	171	0	0.0%	95.5%	0.0%	0			0	0	0.00	
22	*Fort Myers 3B*												
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	170	0	0.0%	95.5%	0.0%	0			0	0	0.00	
26	*Fort Myers 4A*												
27	Light Oil		0					0	0	0	0	0.00	0.00
28	Gas		5,250					61,780	1,000,000	61,780	313,772	5.98	5.08
29	Plant Unit Info	223	5,250	3.3%	93.9%	67.3%	11,768			61,780	313,772	5.98	
30	*Fort Myers 4B*												
31	Light Oil		0					0	0	0	0	0.00	0.00
32	Gas		2,850					33,772	1,000,000	33,772	171,525	6.02	5.08
33	Plant Unit Info	222	2,850	1.8%	93.9%	67.5%	11,850			33,772	171,525	6.02	
34	*Lauderdale 4*												
35	Light Oil		0					0	0	0	0	0.00	0.00
36	Gas		28,088					256,649	1,000,000	256,649	1,302,772	4.64	5.08
37	Plant Unit Info	441	28,088	8.9%	93.9%	75.9%	9,137			256,649	1,302,772	4.64	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	*Lauderdale 5*												
2	Light Oil		0					0	0	0	0	0.00	0.00
3	Gas		32,849					299,734	1,000,000	299,734	1,521,592	4.63	5.08
4	Plant Unit Info	441	32,849	10.4%	93.9%	69.0%	9,125			299,734	1,521,592	4.63	
5	*Lauderdale 6 CT 1*												
6	Light Oil		0					0	0	0	0	0.00	0.00
7	Gas		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	201	0	0.0%	72.2%	0.0%	0			0	0	0.00	
9	*Lauderdale 6 CT 2*												
10	Light Oil		0					0	0	0	0	0.00	0.00
11	Gas		0					0	0	0	0	0.00	0.00
12	Plant Unit Info	201	0	0.0%	72.2%	0.0%	0			0	0	0.00	
13	*Lauderdale 6 CT 3*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	202	0	0.0%	72.2%	0.0%	0			0	0	0.00	
17	*Lauderdale 6 CT 4*												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	202	0	0.0%	72.2%	0.0%	0			0	0	0.00	
21	*Lauderdale 6 CT 5*												
22	Light Oil		0					0	0	0	0	0.00	0.00
23	Gas		0					0	0	0	0	0.00	0.00
24	Plant Unit Info	202	0	0.0%	72.2%	0.0%	0			0	0	0.00	
25	*Manatee 1*												
26	Heavy Oil		105					266	6,400,000	1,702	18,041	17.20	67.84
27	Gas		22,142					359,293	1,000,000	359,293	1,806,748	8.16	5.03
28	Plant Unit Info	788	22,247	3.9%	96.2%	25.7%	16,227			360,995	1,824,789	8.20	
29	*Manatee 2*												
30	Heavy Oil		62					178	6,400,000	1,140	12,084	19.47	67.84
31	Gas		6,442					118,330	1,000,000	118,330	595,388	9.24	5.03
32	Plant Unit Info	792	6,504	1.1%	63.0%	25.7%	18,369			119,470	607,472	9.34	
33	*Manatee 3*												
34	Gas		575,705					4,081,478	1,000,000	4,081,478	20,468,543	3.56	5.01
35	Plant Unit Info	1,158	575,705	69.1%	94.1%	80.4%	7,090			4,081,478	20,468,543	3.56	
36	*Manatee PV Solar*												
37	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Plant Unit Info	75	0	14.7%	N/A	32.0%	N/A			0	0	0.00	
2	*Martin 1*												
3	Heavy Oil		0					0	0	0	0	0.00	0.00
4	Gas		0					0	0	0	0	0.00	0.00
5	Plant Unit Info	797	0	0.0%	96.3%	0.0%	0			0	0	0.00	
6	*Martin 2*												
7	Heavy Oil		0					0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	766	0	0.0%	96.3%	0.0%	0			0	0	0.00	
10	*Martin 3*												
11	Gas		85,117					726,444	1,000,000	726,444	3,647,609	4.29	5.02
12	Plant Unit Info	479	85,117	24.7%	94.1%	71.1%	8,535			726,444	3,647,609	4.29	
13	*Martin 4*												
14	Gas		67,051					575,954	1,000,000	575,954	2,890,965	4.31	5.02
15	Plant Unit Info	433	67,051	21.5%	94.1%	76.3%	8,590			575,954	2,890,965	4.31	
16	*Martin 8*												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		542,865					3,886,542	1,000,000	3,886,542	19,490,457	3.59	5.01
19	Plant Unit Info	1,112	542,865	67.8%	93.8%	81.8%	7,159			3,886,542	19,490,457	3.59	
20	*Martin 8 Solar*												
21	Solar		6,510					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	75	6,510	12.1%	N/A	20.7%	N/A			0	0	0.00	
23	*PEEC*												
24	Light Oil		10,047					11,527	5,830,000	67,200	829,786	8.26	71.99
25	Gas		564,850					3,778,137	1,000,000	3,778,137	19,186,674	3.40	5.08
26	Plant Unit Info	1,216	574,897	65.7%	93.5%	65.7%	6,689			3,845,337	20,016,459	3.48	
27	*Riviera 5*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		625,169					4,139,605	1,000,000	4,139,605	20,916,552	3.35	5.05
30	Plant Unit Info	1,216	625,169	71.4%	93.8%	71.4%	6,622			4,139,605	20,916,552	3.35	
31	*Sanford 4*												
32	Gas		277,165					2,277,738	1,000,000	2,277,738	11,566,079	4.17	5.08
33	Plant Unit Info	1,020	277,165	37.7%	94.1%	67.4%	8,218			2,277,738	11,566,079	4.17	
34	*Sanford 5*												
35	Gas		235,323					1,908,369	1,000,000	1,908,369	9,690,311	4.12	5.08
36	Plant Unit Info	1,020	235,323	32.0%	94.1%	71.2%	8,110			1,908,369	9,690,311	4.12	
37	*Scherer 4*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Coal		324,161					206,082	17,000,000	3,503,393	8,076,111	2.49	39.19
2	Plant Unit Info	599	324,161	75.2%	95.0%	75.2%	10,808			3,503,393	8,076,111	2.49	
3	*St Johns 1*												
4	Coal		50,782					25,702	22,000,000	565,449	1,950,738	3.84	75.90
5	Plant Unit Info	125	50,782	56.3%	94.8%	56.3%	11,135			565,449	1,950,738	3.84	
6	*St Johns 2*												
7	Coal		49,342					24,927	22,000,000	548,398	1,891,915	3.83	75.90
8	Plant Unit Info	125	49,342	54.7%	94.8%	54.7%	11,114			548,398	1,891,915	3.83	
9	*St Lucie 1*												
10	Nuclear		704,592					7,277,024	1,000,000	7,277,024	4,584,525	0.65	0.63
11	Plant Unit Info	1,004	704,592	97.5%	97.5%	97.5%	10,328			7,277,024	4,584,525	0.65	
12	*St Lucie 2*												
13	Nuclear		603,236					6,168,685	1,000,000	6,168,685	4,318,077	0.72	0.70
14	Plant Unit Info	859	603,236	97.5%	97.5%	97.5%	10,226			6,168,685	4,318,077	0.72	
15	*Space Coast*												
16	Solar		1,170					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	10	1,170	16.3%	N/A	43.3%	N/A			0	0	0.00	
18	*Turkey Point 3*												
19	Nuclear		588,978					6,402,194	1,000,000	6,402,194	3,905,338	0.66	0.61
20	Plant Unit Info	839	588,978	97.5%	97.5%	97.5%	10,870			6,402,194	3,905,338	0.66	
21	*Turkey Point 4*												
22	Nuclear		595,296					6,470,866	1,000,000	6,470,866	3,817,813	0.64	0.59
23	Plant Unit Info	848	595,296	97.5%	97.5%	97.5%	10,870			6,470,866	3,817,813	0.64	
24	*Turkey Point 5*												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		58,349					443,428	1,000,000	443,428	2,252,114	3.86	5.08
27	Plant Unit Info	1,178	58,349	6.9%	9.1%	40.6%	7,600			443,428	2,252,114	3.86	
28	*WCEC 01*												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		434,743					3,281,938	1,000,000	3,281,938	16,451,669	3.78	5.01
31	Plant Unit Info	1,208	434,743	50.0%	94.0%	76.7%	7,549			3,281,938	16,451,669	3.78	
32	*WCEC 02*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		568,052					4,017,125	1,000,000	4,017,125	20,137,281	3.54	5.01
35	Plant Unit Info	1,198	568,052	65.9%	94.0%	65.9%	7,072			4,017,125	20,137,281	3.54	
36	*WCEC 03*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Gas		17,727					147,308	1,000,000	147,308	738,549	4.17	5.01
2	Plant Unit Info	1,207	17,727	1.7%	1.7%	30.6%	8,310			147,308	738,549	4.17	
3	**System Totals**												
4	Plant Unit Info	25,900	8,293,511				8,444			70,031,412	226,802,257	3	
5													
6													
7													
8													
9													
10													
11													
12													
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ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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 - 2017**												
2	*Babcock PV Solar*												
3	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
4	Plant Unit Info	75	0	13.0%	N/A	31.2%	N/A			0	0	0.00	
5	*CCEC 3*												
6	Light Oil		6,803					7,822	5,830,000	45,600	607,481	8.93	77.67
7	Gas		535,137					3,586,821	1,000,000	3,586,821	18,478,485	3.45	5.15
8	Plant Unit Info	1,234	541,940	59.0%	73.4%	59.0%	6,703			3,632,421	19,085,966	3.52	
9	*Citrus PV Solar*												
10	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A
11	Plant Unit Info	75	0	13.0%	N/A	31.2%	N/A			0	0	0.00	
12	*Desoto Solar*												
13	Solar		3,193					N/A	N/A	N/A	N/A	N/A	N/A
14	Plant Unit Info	25	3,193	17.2%	N/A	45.8%	N/A			0	0	0.00	
15	*Fort Myers 2*												
16	Gas		751,016					5,570,519	1,000,000	5,570,519	28,698,528	3.82	5.15
17	Plant Unit Info	1,669	751,016	45.6%	45.6%	60.5%	7,417			5,570,519	28,698,528	3.82	
18	*Fort Myers 3A*												
19	Light Oil		0					0	0	0	0	0.00	0.00
20	Gas		499					5,984	1,000,000	5,984	30,835	6.18	5.15
21	Plant Unit Info	181	499	0.4%	95.5%	68.8%	11,992			5,984	30,835	6.18	
22	*Fort Myers 3B*												
23	Light Oil		0					0	0	0	0	0.00	0.00
24	Gas		499					5,984	1,000,000	5,984	30,835	6.18	5.15
25	Plant Unit Info	181	499	0.4%	95.5%	68.8%	11,992			5,984	30,835	6.18	
26	*Fort Myers 4A*												
27	Light Oil		0					0	0	0	0	0.00	0.00
28	Gas		3,379					39,043	1,000,000	39,043	201,195	5.95	5.15
29	Plant Unit Info	223	3,379	2.0%	71.3%	75.9%	11,555			39,043	201,195	5.95	
30	*Fort Myers 4B*												
31	Light Oil		0					0	0	0	0	0.00	0.00
32	Gas		14,315					164,458	1,000,000	164,458	847,478	5.92	5.15
33	Plant Unit Info	223	14,315	8.6%	71.3%	68.3%	11,489			164,458	847,478	5.92	
34	*Lauderdale 4*												
35	Light Oil		0					0	0	0	0	0.00	0.00
36	Gas		9,992					91,666	1,000,000	91,666	472,369	4.73	5.15
37	Plant Unit Info	440	9,992	3.1%	93.9%	59.7%	9,174			91,666	472,369	4.73	

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	*Lauderdale 5*												
2	Light Oil		0					0	0	0	0	0.00	0.00
3	Gas		34,451					314,573	1,000,000	314,573	1,621,046	4.71	5.15
4	Plant Unit Info	441	34,451	10.5%	93.9%	63.5%	9,131			314,573	1,621,046	4.71	
5	*Lauderdale 6 CT 1*												
6	Light Oil		0					0	0	0	0	0.00	0.00
7	Gas		0					0	0	0	0	0.00	0.00
8	Plant Unit Info	201	0	0.0%	95.5%	0.0%	0			0	0	0.00	
9	*Lauderdale 6 CT 2*												
10	Light Oil		26					51	5,830,000	300	4,632	18.05	90.02
11	Gas		620					7,252	1,000,000	7,252	37,372	6.02	5.15
12	Plant Unit Info	202	646	0.4%	95.5%	80.0%	11,690			7,552	42,004	6.50	
13	*Lauderdale 6 CT 3*												
14	Light Oil		0					0	0	0	0	0.00	0.00
15	Gas		0					0	0	0	0	0.00	0.00
16	Plant Unit Info	202	0	0.0%	95.5%	0.0%	0			0	0	0.00	
17	*Lauderdale 6 CT 4*												
18	Light Oil		0					0	0	0	0	0.00	0.00
19	Gas		0					0	0	0	0	0.00	0.00
20	Plant Unit Info	202	0	0.0%	95.5%	0.0%	0			0	0	0.00	
21	*Lauderdale 6 CT 5*												
22	Light Oil		0					0	0	0	0	0.00	0.00
23	Gas		0					0	0	0	0	0.00	0.00
24	Plant Unit Info	202	0	0.0%	95.5%	0.0%	0			0	0	0.00	
25	*Manatee 1*												
26	Heavy Oil		0					0	0	0	0	0.00	0.00
27	Gas		3,329					60,879	1,000,000	60,879	311,030	9.34	5.11
28	Plant Unit Info	785	3,329	0.6%	96.2%	26.5%	18,287			60,879	311,030	9.34	
29	*Manatee 2*												
30	Heavy Oil		0					0	0	0	0	0.00	0.00
31	Gas		0					0	0	0	0	0.00	0.00
32	Plant Unit Info	792	0	0.0%	96.3%	0.0%	0			0	0	0.00	
33	*Manatee 3*												
34	Gas		322,208					2,350,175	1,000,000	2,350,175	11,956,610	3.71	5.09
35	Plant Unit Info	1,158	322,208	37.4%	94.1%	83.1%	7,294			2,350,175	11,956,610	3.71	
36	*Manatee PV Solar*												
37	Solar		0					N/A	N/A	N/A	N/A	N/A	N/A

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Plant Unit Info	75	0	13.0%	N/A	31.2%	N/A			0	0	0.00	
2	*Martin 1*												
3	Heavy Oil		774					1,909	6,400,000	12,217	139,286	18.00	72.97
4	Gas		5,823					91,946	1,000,000	91,946	471,172	8.09	5.12
5	Plant Unit Info	806	6,597	1.1%	96.3%	34.1%	15,789			104,163	610,457	9.25	
6	*Martin 2*												
7	Heavy Oil		0					0	0	0	0	0.00	0.00
8	Gas		0					0	0	0	0	0.00	0.00
9	Plant Unit Info	766	0	0.0%	96.3%	0.0%	0			0	0	0.00	
10	*Martin 3*												
11	Gas		61,221					497,014	1,000,000	497,014	2,533,901	4.14	5.10
12	Plant Unit Info	479	61,221	17.2%	94.1%	80.9%	8,118			497,014	2,533,901	4.14	
13	*Martin 4*												
14	Gas		57,933					483,640	1,000,000	483,640	2,462,323	4.25	5.09
15	Plant Unit Info	433	57,933	18.0%	94.1%	82.1%	8,348			483,640	2,462,323	4.25	
16	*Martin 8*												
17	Light Oil		0					0	0	0	0	0.00	0.00
18	Gas		523,643					3,654,050	1,000,000	3,654,050	18,580,355	3.55	5.08
19	Plant Unit Info	1,112	523,643	63.3%	93.8%	63.3%	6,978			3,654,050	18,580,355	3.55	
20	*Martin 8 Solar*												
21	Solar		5,425					N/A	N/A	N/A	N/A	N/A	N/A
22	Plant Unit Info	75	5,425	9.7%	N/A	17.9%	N/A			0	0	0.00	
23	*PEEC*												
24	Light Oil		3,610					4,117	5,830,000	24,000	296,352	8.21	71.99
25	Gas		534,000					3,550,033	1,000,000	3,550,033	18,287,114	3.42	5.15
26	Plant Unit Info	1,216	537,610	59.4%	63.4%	59.4%	6,648			3,574,033	18,583,466	3.46	
27	*Riviera 5*												
28	Light Oil		0					0	0	0	0	0.00	0.00
29	Gas		484,749					3,294,691	1,000,000	3,294,691	16,883,484	3.48	5.12
30	Plant Unit Info	1,216	484,749	53.6%	93.8%	53.6%	6,797			3,294,691	16,883,484	3.48	
31	*Sanford 4*												
32	Gas		86,502					743,290	1,000,000	743,290	3,829,127	4.43	5.15
33	Plant Unit Info	1,020	86,502	11.4%	94.1%	58.9%	8,593			743,290	3,829,127	4.43	
34	*Sanford 5*												
35	Gas		111,425					951,247	1,000,000	951,247	4,900,117	4.40	5.15
36	Plant Unit Info	1,020	111,425	14.7%	94.1%	60.7%	8,537			951,247	4,900,117	4.40	
37	*Scherer 4*												

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Coal		368,437					231,689	17,000,000	3,938,707	9,112,423	2.47	39.33
2	Plant Unit Info	599	368,437	82.7%	95.0%	82.7%	10,690			3,938,707	9,112,423	2.47	
3	*St Johns 1*												
4	Coal		59,174					30,087	22,000,000	661,909	2,233,717	3.77	74.24
5	Plant Unit Info	125	59,174	63.5%	94.8%	63.5%	11,186			661,909	2,233,717	3.77	
6	*St Johns 2*												
7	Coal		57,308					29,063	22,000,000	639,396	2,157,744	3.77	74.24
8	Plant Unit Info	125	57,308	61.5%	94.8%	61.5%	11,157			639,396	2,157,744	3.77	
9	*St Lucie 1*												
10	Nuclear		728,079					7,519,591	1,000,000	7,519,591	4,737,343	0.65	0.63
11	Plant Unit Info	1,004	728,079	97.5%	97.5%	97.5%	10,328			7,519,591	4,737,343	0.65	
12	*St Lucie 2*												
13	Nuclear		623,343					6,374,307	1,000,000	6,374,307	4,462,013	0.72	0.70
14	Plant Unit Info	859	623,343	97.5%	97.5%	97.5%	10,226			6,374,307	4,462,013	0.72	
15	*Space Coast*												
16	Solar		1,054					N/A	N/A	N/A	N/A	N/A	N/A
17	Plant Unit Info	10	1,054	14.2%	N/A	37.8%	N/A			0	0	0.00	
18	*Turkey Point 3*												
19	Nuclear		608,611					6,615,601	1,000,000	6,615,601	4,035,516	0.66	0.61
20	Plant Unit Info	839	608,611	97.5%	97.5%	97.5%	10,870			6,615,601	4,035,516	0.66	
21	*Turkey Point 4*												
22	Nuclear		615,139					6,686,561	1,000,000	6,686,561	3,945,074	0.64	0.59
23	Plant Unit Info	848	615,139	97.5%	97.5%	97.5%	10,870			6,686,561	3,945,074	0.64	
24	*Turkey Point 5*												
25	Light Oil		0					0	0	0	0	0.00	0.00
26	Gas		74,844					574,906	1,000,000	574,906	2,962,155	3.96	5.15
27	Plant Unit Info	1,178	74,844	8.5%	48.1%	41.3%	7,681			574,906	2,962,155	3.96	
28	*WCEC 01*												
29	Light Oil		0					0	0	0	0	0.00	0.00
30	Gas		695,385					4,826,722	1,000,000	4,826,722	24,537,631	3.53	5.08
31	Plant Unit Info	1,208	695,385	77.4%	94.0%	77.4%	6,941			4,826,722	24,537,631	3.53	
32	*WCEC 02*												
33	Light Oil		0					0	0	0	0	0.00	0.00
34	Gas		701,184					4,859,599	1,000,000	4,859,599	24,703,782	3.52	5.08
35	Plant Unit Info	1,198	701,184	78.7%	94.0%	78.7%	6,931			4,859,599	24,703,782	3.52	
36	*WCEC 03*												
37	Light Oil		0					0	0	0	0	0.00	0.00

FLORIDA POWER & LIGHT COMPANY
GENERATING SYSTEM FUEL DETAILS

SCHEDULE: E4

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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	Gas		443,928					3,197,771	1,000,000	3,197,771	16,257,023	3.66	5.08
2	Plant Unit Info	1,208	443,928	49.4%	59.6%	49.4%	7,203			3,197,771	16,257,023	3.66	
3	**System Totals**												
4	Plant Unit Info	25,930	8,537,058				8,368			71,440,453	230,825,547	3	
5													
6													
7													
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FLORIDA POWER & LIGHT COMPANY
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

Line No.	(1)	(2) Jan - 2017	(3) Feb - 2017	(4) Mar - 2017	(5) Apr - 2017	(6) May - 2017	(7) Jun - 2017	(8) Jul - 2017	(9) Aug - 2017	(10) Sep - 2017	(11) Oct - 2017	(12) Nov - 2017	(13) Dec - 2017	(14) 2017
1	**#6 Heavy Oil (BBLS)**													
2	Purchases													
3	Units	0	0	0	0	0	145,000	0	0	0	0	0	0	145,000
4	Unit Cost	0.0000	0.0000	0.0000	0.0000	0.0000	49.1379	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	49.1379
5	Amount	$0	$0	$0	$0	$0	$7,125,000	$0	$0	$0	$0	$0	$0	$7,125,000
6	Burned													
7	Units	11,683	7,640	7,473	11,259	33,270	39,538	27,409	44,783	14,346	12,207	444	1,909	211,962
8	Unit Cost	71.3408	70.7856	70.6100	72.5844	72.4636	70.2954	70.0292	70.4948	69.8212	70.9205	67.8397	72.9663	70.8742
9	Amount	$833,461	$540,835	$527,678	$817,243	$2,410,865	$2,779,368	$1,919,402	$3,156,976	$1,001,683	$865,707	$30,125	$139,286	$15,022,630
10	Ending Inventory													
11	Units	2,460,491	2,452,851	2,445,377	2,434,118	2,400,848	2,506,310	2,478,901	2,434,118	2,419,772	2,407,565	2,407,121	2,405,212	2,405,212
12	Unit Cost	71.6560	71.6587	71.6617	71.6580	71.6468	70.3656	70.3695	70.3668	70.3703	70.3669	70.3675	70.3655	70.3655
13	Amount	$176,309,000	$175,768,000	$175,240,000	$174,424,000	$172,013,000	$176,358,000	$174,439,000	$171,281,000	$170,280,000	$169,413,000	$169,383,000	$169,244,000	$169,244,000
14	**#2 Light Oil (BBLS)**													
15	Purchases													
16	Units	20,197	0	30,994	73,031	0	30,875	30,463	25,523	0	73,632	33,551	0	318,266
17	Unit Cost	64.2662	0.0000	65.1420	65.1777	0.0000	65.8466	66.3097	66.8021	0.0000	67.9327	68.4638	0.0000	66.4037
18	Amount	$1,298,000	$0	$2,019,000	$4,760,000	$0	$2,033,000	$2,020,000	$1,705,000	$0	$5,002,000	$2,297,000	$0	$21,134,000
19	Burned													
20	Units	12,662	6,459	24,145	30,924	39,397	26,758	26,855	22,401	18,823	32,988	20,172	11,990	273,574
21	Unit Cost	105.0415	105.2544	95.2306	92.5298	89.7866	89.4488	84.1067	82.3265	78.8094	81.4618	74.4223	75.7704	86.9407
22	Amount	$1,330,027	$679,803	$2,299,387	$2,861,408	$3,537,347	$2,393,469	$2,258,720	$1,844,156	$1,483,427	$2,687,275	$1,501,212	$908,465	$23,784,696
23	Ending Inventory													
24	Units	1,246,887	1,240,428	1,247,277	1,289,384	1,249,986	1,254,103	1,257,711	1,260,833	1,242,010	1,282,654	1,296,033	1,284,043	1,284,043
25	Unit Cost	101.5962	101.5778	100.7948	98.9760	99.2651	98.6514	98.1784	97.8250	98.1135	96.8086	96.4235	96.6159	96.6159
26	Amount	$126,679,000	$126,000,000	$125,719,000	$127,618,000	$124,080,000	$123,719,000	$123,480,000	$123,341,000	$121,858,000	$124,172,000	$124,968,000	$124,059,000	$124,059,000
27	**Coal - SJRPP (TONS)**													
28	Purchases													
29	Units	52,632	52,632	52,632	52,632	52,632	52,632	52,632	52,632	52,632	52,632	52,632	52,632	631,582
30	Unit Cost	75.8667	74.5177	74.5177	74.5177	74.5177	71.8197	79.9326	79.9326	79.9326	79.9326	71.2117	71.2117	75.6592
31	Amount	$3,993,000	$3,922,000	$3,922,000	$3,922,000	$3,922,000	$3,780,000	$4,207,000	$4,207,000	$4,207,000	$4,207,000	$3,748,000	$3,748,000	$47,785,000
32	Burned													
33	Units	52,593	44,703	32,536	46,855	58,274	51,120	57,812	60,083	55,065	62,761	50,629	59,150	631,582
34	Unit Cost	71.2811	72.4797	73.1951	73.6050	73.8789	73.2428	75.2885	76.7521	77.8006	78.5137	75.8977	74.2425	74.8572
35	Amount	$3,748,907	$3,240,051	$2,381,472	$3,448,776	$4,305,234	$3,744,180	$4,352,573	$4,611,516	$4,284,064	$4,927,568	$3,842,654	$4,391,461	$47,278,456
36	Ending Inventory													
37	Units	89,644	97,572	117,668	123,445	117,803	119,314	114,134	106,683	104,250	94,121	96,123	89,605	89,605
38	Unit Cost	71.2824	72.4795	73.1973	73.6037	73.8779	73.2436	75.2886	76.7510	77.8035	78.5159	75.9024	74.2369	74.2369
39	Amount	$6,390,000	$7,072,000	$8,613,000	$9,086,000	$8,703,000	$8,739,000	$8,593,000	$8,188,000	$8,111,000	$7,390,000	$7,296,000	$6,652,000	$6,652,000
40														

FLORIDA POWER & LIGHT COMPANY
SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS

SCHEDULE: E5

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

Line No.	(1)	(2) Jan - 2017	(3) Feb - 2017	(4) Mar - 2017	(5) Apr - 2017	(6) May - 2017	(7) Jun - 2017	(8) Jul - 2017	(9) Aug - 2017	(10) Sep - 2017	(11) Oct - 2017	(12) Nov - 2017	(13) Dec - 2017	(14) 2017
1	**Coal - Scherer (MMBTU)**													
2	Purchases													
3	Units	3,876,809	3,876,809	3,876,809	3,876,809	3,876,809	3,876,809	3,876,809	3,876,809	3,876,809	3,876,809	3,876,809	3,876,809	46,521,713
4	Unit Cost	2.2766	2.2704	2.2645	2.2555	2.2493	2.2645	2.2949	2.3161	2.3040	2.3009	2.3130	2.3254	2.2862
5	Amount	$8,826,000	$8,802,000	$8,779,000	$8,744,000	$8,720,000	$8,779,000	$8,897,000	$8,979,000	$8,932,000	$8,920,000	$8,967,000	$9,015,000	$106,360,000
6	Burned													
7	Units	3,779,509	3,711,036	4,232,129	3,897,358	3,882,869	3,509,946	4,038,572	3,955,974	3,862,384	4,209,836	3,503,393	3,938,707	46,521,713
8	Unit Cost	2.3564	2.3208	2.2979	2.2799	2.2669	2.2659	2.2777	2.2936	2.2980	2.2992	2.3052	2.3136	2.2979
9	Amount	$8,906,164	$8,612,729	$9,724,950	$8,885,555	$8,802,107	$7,953,080	$9,198,620	$9,073,582	$8,875,625	$9,679,285	$8,076,111	$9,112,423	$106,900,230
10	Ending Inventory													
11	Units	5,479,111	5,644,885	5,289,565	5,269,017	5,262,957	5,629,821	5,468,058	5,388,893	5,403,319	5,070,292	5,443,709	5,381,811	5,381,811
12	Unit Cost	2.3564	2.3209	2.2979	2.2799	2.2670	2.2658	2.2778	2.2936	2.2980	2.2993	2.3052	2.3135	2.3135
13	Amount	$12,911,000	$13,101,000	$12,155,000	$12,013,000	$11,931,000	$12,756,000	$12,455,000	$12,360,000	$12,417,000	$11,658,000	$12,549,000	$12,451,000	$12,451,000
14	**Gas (MCF)**													
15	Burned													
16	Units	42,428,295	39,512,841	46,899,039	47,807,528	51,798,365	54,983,600	58,482,050	59,955,640	55,260,875	53,967,411	38,974,961	38,922,263	588,992,868
17	Unit Cost	4.4230	4.3925	4.3084	4.2062	4.1408	4.0775	4.4920	4.4684	4.5182	4.5255	5.0475	5.1152	4.4540
18	Amount	$187,661,398	$173,559,532	$202,061,684	$201,089,272	$214,489,243	$224,197,958	$262,703,831	$267,903,024	$249,676,979	$244,227,057	$196,726,403	$199,093,967	$2,623,390,342
19	**Nuclear (Other)**													
20	Burned													
21	Units	28,424,310	23,707,864	21,424,632	20,736,862	27,134,946	26,259,626	27,134,946	27,134,946	26,259,626	20,683,951	26,318,769	27,196,060	302,416,541
22	Unit Cost	0.6515	0.6491	0.6425	0.6438	0.6367	0.6367	0.6367	0.6367	0.6367	0.6450	0.6317	0.6317	0.6396
23	Amount	$18,517,813	$15,389,090	$13,764,482	$13,349,653	$17,275,823	$16,718,540	$17,275,823	$17,275,823	$16,718,540	$13,340,715	$16,625,753	$17,179,946	$193,431,998
24														
25	Note: Totals may not add due to rounding.													

FLORIDA POWER & LIGHT COMPANY
POWER SOLD

SCHEDULE: E6

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

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(4) * Col(5))	Total Cost ($) (Col(4) * Col(6))	Gain from Off System Sales ($)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1									
2	**January Estimated**								
3	Off System	OS	573,200	573,200	2.409	3.273	$13,810,728	$18,758,228	$3,554,552
4	St Lucie Reliability Sales		54,226	54,226	0.689	0.689	$373,719	$373,719	$0
5	**Total January Estimated**		627,426	627,426	2.261	3.049	$14,184,447	$19,131,947	$3,554,552
6									
7	**February Estimated**								
8	Off System	OS	456,600	456,600	2.556	3.365	$11,668,440	$15,365,940	$2,577,176
9	St Lucie Reliability Sales		48,978	48,978	0.689	0.689	$337,553	$337,553	$0
10	**Total February Estimated**		505,578	505,578	2.375	3.106	$12,005,993	$15,703,493	$2,577,176
11									
12	**March Estimated**								
13	Off System	OS	244,400	244,400	2.593	3.211	$6,336,193	$7,847,793	$827,784
14	St Lucie Reliability Sales		54,226	54,226	0.689	0.689	$373,719	$373,719	$0
15	**Total March Estimated**		298,626	298,626	2.247	2.753	$6,709,912	$8,221,512	$827,784
16									
17	**April Estimated**								
18	Off System	OS	165,000	165,000	2.606	3.418	$4,300,093	$5,640,093	$859,000
19	St Lucie Reliability Sales		49,867	49,867	0.689	0.689	$343,681	$343,681	$0
20	**Total April Estimated**		214,867	214,867	2.161	2.785	$4,643,774	$5,983,774	$859,000
21									
22	**May Estimated**								
23	Off System	OS	87,500	87,500	3.130	4.213	$2,739,139	$3,686,639	$678,375
24	St Lucie Reliability Sales		51,529	51,529	0.689	0.689	$355,137	$355,137	$0
25	**Total May Estimated**		139,029	139,029	2.226	2.907	$3,094,276	$4,041,776	$678,375
26									
27	**June Estimated**								
28	Off System	OS	60,000	60,000	3.069	4.192	$1,841,181	$2,514,931	$488,625
29	St Lucie Reliability Sales		49,867	49,867	0.689	0.689	$343,681	$343,681	$0
30	**Total June Estimated**		109,867	109,867	1.989	2.602	$2,184,862	$2,858,612	$488,625
31									
32	**6 Month Period**								
33	Off System	OS	1,586,700	1,586,700	2.565	3.392	$40,695,773	$53,813,623	$8,985,512
34	St Lucie Reliability Sales		308,693	308,693	0.689	0.689	$2,127,491	$2,127,491	$0
35	**Total 6 Month Period**		1,895,393	1,895,393	2.259	2.951	$42,823,264	$55,941,114	$8,985,512
36									
37									
38									

FLORIDA POWER & LIGHT COMPANY
POWER SOLD

SCHEDULE: E6

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

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(4) * Col(5))	Total Cost ($) (Col(4) * Col(6))	Gain from Off System Sales ($)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1									
2	**July Estimated**								
3	Off System	OS	58,000	58,000	3.257	4.663	$1,888,853	$2,704,603	$605,625
4	St Lucie Reliability Sales		51,529	51,529	0.689	0.689	$355,137	$355,137	$0
5	**Total July Estimated**		109,529	109,529	2.049	2.794	$2,243,990	$3,059,740	$605,625
6									
7	**August Estimated**								
8	Off System	OS	58,000	58,000	3.948	5.354	$2,290,043	$3,105,168	$605,000
9	St Lucie Reliability Sales		51,529	51,529	0.689	0.689	$355,137	$355,137	$0
10	**Total August Estimated**		109,529	109,529	2.415	3.159	$2,645,181	$3,460,306	$605,000
11									
12	**September Estimated**								
13	Off System	OS	73,000	73,000	3.249	4.531	$2,371,731	$3,307,981	$683,125
14	St Lucie Reliability Sales		49,867	49,867	0.689	0.689	$343,681	$343,681	$0
15	**Total September Estimated**		122,867	122,867	2.210	2.972	$2,715,413	$3,651,663	$683,125
16									
17	**October Estimated**								
18	Off System	OS	66,000	66,000	2.751	3.598	$1,815,522	$2,374,522	$362,750
19	St Lucie Reliability Sales		51,529	51,529	0.689	0.689	$355,137	$355,137	$0
20	**Total October Estimated**		117,529	117,529	1.847	2.323	$2,170,659	$2,729,659	$362,750
21									
22	**November Estimated**								
23	Off System	OS	96,000	96,000	2.466	3.272	$2,367,108	$3,141,108	$490,500
24	St Lucie Reliability Sales		49,896	49,896	0.689	0.689	$343,883	$343,883	$0
25	**Total November Estimated**		145,896	145,896	1.858	2.389	$2,710,991	$3,484,991	$490,500
26									
27	**December Estimated**								
28	Off System	OS	158,000	158,000	2.506	3.271	$3,960,067	$5,168,067	$711,000
29	St Lucie Reliability Sales		51,560	51,560	0.689	0.689	$355,346	$355,346	$0
30	**Total December Estimated**		209,560	209,560	2.059	2.636	$4,315,413	$5,523,413	$711,000
31									
32	**12 Month Period**								
33	Off System	OS	2,095,700	2,095,700	2.643	3.513	$55,389,097	$73,615,072	$12,443,512
34	St Lucie Reliability Sales		614,604	614,604	0.689	0.689	$4,235,814	$4,235,814	$0
35	**Total 12 Month Period**		2,710,304	2,710,304	2.200	2.872	$59,624,910	$77,850,885	$12,443,512
36									
37									
38	Note: Totals may not add due to rounding.								

FLORIDA POWER & LIGHT COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

SCHEDULE: E7

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)
Line No.	PURCHASE FROM	Type & Schedule	Total KWH Purchased (000)	KWH For Firm (000)	Fuel Cost (cents/KWH)	Total $ For Fuel Adj (Col(4) * Col(5))
1						
2	**January Estimated**					
3	SJRPP		156,311	156,311	3.598	$5,623,361
4	St Lucie Reliability		46,425	46,425	0.734	$340,936
5	SWA		77,376	77,376	3.382	$2,617,127
6	**Total January Estimated**		280,112	280,112	3.064	$8,581,424
7						
8	**February Estimated**					
9	SJRPP		131,768	131,768	3.688	$4,860,077
10	St Lucie Reliability		28,454	28,454	0.734	$208,961
11	SWA		69,888	69,888	3.382	$2,363,857
12	**Total February Estimated**		230,110	230,110	3.230	$7,432,894
13						
14	**March Estimated**					
15	SJRPP		96,059	96,059	3.719	$3,572,208
16	St Lucie Reliability		5,990	5,990	0.755	$45,248
17	SWA		77,376	77,376	3.382	$2,617,127
18	**Total March Estimated**		179,426	179,426	3.475	$6,234,583
19						
20	**April Estimated**					
21	SJRPP		137,441	137,441	3.764	$5,173,165
22	St Lucie Reliability		42,261	42,261	0.755	$319,216
23	SWA		74,880	74,880	3.382	$2,532,704
24	**Total April Estimated**		254,582	254,582	3.152	$8,025,084
25						
26	**May Estimated**					
27	SJRPP		170,311	170,311	3.792	$6,457,850
28	St Lucie Reliability		43,670	43,670	0.755	$329,857
29	SWA		77,376	77,376	3.382	$2,617,127
30	**Total May Estimated**		291,357	291,357	3.228	$9,404,834
31						
32	**June Estimated**					
33	SJRPP		150,275	150,275	3.737	$5,616,270
34	St Lucie Reliability		42,261	42,261	0.755	$319,216
35	SWA		74,880	74,880	3.382	$2,532,704
36	**Total June Estimated**		267,416	267,416	3.167	$8,468,190
37						
38	**6 Month Period**					
39	SJRPP		842,166	842,166	3.717	$31,302,931
40	St Lucie Reliability		209,061	209,061	0.748	$1,563,434
41	SWA		451,776	451,776	3.382	$15,280,645
42	**Total 6 Month Period**		1,503,003	1,503,003	3.203	$48,147,010
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FLORIDA POWER & LIGHT COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

SCHEDULE: E7

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

Line No.	PURCHASE FROM	Type & Schedule	Total KWH Purchased (000)	KWH For Firm (000)	Fuel Cost (cents/KWH)	Total $ For Fuel Adj (Col(4) * Col(5))
	(1)	(2)	(3)	(4)	(5)	(6)
1						
2	**July Estimated**					
3	SJRPP		169,862	169,862	3.844	$6,528,860
4	St Lucie Reliability		43,670	43,670	0.755	$329,857
5	SWA		77,376	77,376	3.382	$2,617,127
6	**Total July Estimated**		290,908	290,908	3.257	$9,475,844
7						
8	**August Estimated**					
9	SJRPP		176,092	176,092	3.928	$6,917,273
10	St Lucie Reliability		43,670	43,670	0.755	$329,857
11	SWA		77,376	77,376	3.382	$2,617,127
12	**Total August Estimated**		297,137	297,137	3.320	$9,864,257
13						
14	**September Estimated**					
15	SJRPP		162,000	162,000	3.967	$6,426,096
16	St Lucie Reliability		42,261	42,261	0.755	$319,216
17	SWA		74,880	74,880	3.382	$2,532,704
18	**Total September Estimated**		279,141	279,141	3.324	$9,278,016
19						
20	**October Estimated**					
21	SJRPP		183,758	183,758	4.022	$7,391,352
22	St Lucie Reliability		43,670	43,670	0.755	$329,857
23	SWA		77,376	77,376	3.382	$2,617,127
24	**Total October Estimated**		304,804	304,804	3.392	$10,338,336
25						
26	**November Estimated**					
27	SJRPP		150,185	150,185	3.838	$5,763,980
28	St Lucie Reliability		42,297	42,297	0.755	$319,487
29	SWA		74,880	74,880	3.382	$2,532,704
30	**Total November Estimated**		267,362	267,362	3.223	$8,616,171
31						
32	**December Estimated**					
33	SJRPP		174,723	174,723	3.770	$6,587,191
34	St Lucie Reliability		43,707	43,707	0.755	$330,136
35	SWA		77,376	77,376	3.382	$2,617,127
36	**Total December Estimated**		295,806	295,806	3.223	$9,534,454
37						
38	**12 Month Period**					
39	SJRPP		1,858,787	1,858,787	3.815	$70,917,684
40	St Lucie Reliability		468,335	468,335	0.752	$3,521,842
41	SWA		911,040	911,040	3.382	$30,814,561
42	**Total 12 Month Period**		3,238,162	3,238,162	3.250	$105,254,087
43						
44						
45	Note: Totals may not add due to rounding.					
46						
47						
48						
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FLORIDA POWER & LIGHT COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES

SCHEDULE: E8

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)
Line No.	PURCHASE FROM	Type & Schedule	Total KWH Purchased (000)	KWH For Firm (000)	Fuel Cost (cents/KWH)	Total $ For Fuel Adj (Col(4) * Col(5))
1						
2	**January Estimated**					
3	Qualifying Facilities		59,619	59,619	3.735	$2,226,780
4	**Total January Estimated**		59,619	59,619	3.735	$2,226,780
5						
6	**February Estimated**					
7	Qualifying Facilities		55,034	55,034	3.616	$1,989,948
8	**Total February Estimated**		55,034	55,034	3.616	$1,989,948
9						
10	**March Estimated**					
11	Qualifying Facilities		51,531	51,531	3.574	$1,841,604
12	**Total March Estimated**		51,531	51,531	3.574	$1,841,604
13						
14	**April Estimated**					
15	Qualifying Facilities		62,865	62,865	3.921	$2,465,140
16	**Total April Estimated**		62,865	62,865	3.921	$2,465,140
17						
18	**May Estimated**					
19	Qualifying Facilities		92,702	92,702	4.276	$3,963,985
20	**Total May Estimated**		92,702	92,702	4.276	$3,963,985
21						
22	**June Estimated**					
23	Qualifying Facilities		55,986	55,986	3.719	$2,082,096
24	**Total June Estimated**		55,986	55,986	3.719	$2,082,096
25						
26	**6 Month Period**					
27	Qualifying Facilities		377,737	377,737	3.857	$14,569,552
28	**Total 6 Month Period**		377,737	377,737	3.857	$14,569,552
29						
30						
31						
32						
33						
34						
35						
36						

FLORIDA POWER & LIGHT COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES

SCHEDULE: E8

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

	(1)	(2)	(3)	(4)	(5)	(6)
Line No.	PURCHASE FROM	Type & Schedule	Total KWH Purchased (000)	KWH For Firm (000)	Fuel Cost (cents/KWH)	Total $ For Fuel Adj (Col(4) * Col(5))
1						
2	**July Estimated**					
3	Qualifying Facilities		119,962	119,962	4.565	$5,475,876
4	**Total July Estimated**		119,962	119,962	4.565	$5,475,876
5						
6	**August Estimated**					
7	Qualifying Facilities		124,316	124,316	4.602	$5,720,658
8	**Total August Estimated**		124,316	124,316	4.602	$5,720,658
9						
10	**September Estimated**					
11	Qualifying Facilities		115,991	115,991	4.537	$5,262,148
12	**Total September Estimated**		115,991	115,991	4.537	$5,262,148
13						
14	**October Estimated**					
15	Qualifying Facilities		111,927	111,927	4.534	$5,074,350
16	**Total October Estimated**		111,927	111,927	4.534	$5,074,350
17						
18	**November Estimated**					
19	Qualifying Facilities		105,970	105,970	4.461	$4,727,249
20	**Total November Estimated**		105,970	105,970	4.461	$4,727,249
21						
22	**December Estimated**					
23	Qualifying Facilities		110,565	110,565	4.519	$4,996,418
24	**Total December Estimated**		110,565	110,565	4.519	$4,996,418
25						
26	**12 Month Period**					
27	Qualifying Facilities		1,066,468	1,066,468	4.297	$45,826,252
28	**Total 12 Month Period**		1,066,468	1,066,468	4.297	$45,826,252
29						
30						
31	Note: Totals may not add due to rounding.					
32						
33						
34						
35						
36						

FLORIDA POWER & LIGHT COMPANY
ECONOMY ENERGY PURCHASES

SCHEDULE: E9

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

Line No.	(1) PURCHASE FROM	(2) Type & Schedule	(3) Total KWH Purchased (000)	(4) Transaction Cost (cents/KWH)	(5) Total $ for Fuel Adj (Col(3) * Col(4))	(6) Cost if Generated (cents/KWH)	(7) Cost if Generated ($) (Col(3) * Col(6))	(8) Fuel Savings ($) (Col(7) - Col(5))
1								
2	**January Estimated**							
3	Economy	OS	13,000	1.946	$252,970	2.384	$309,970	$57,000
4	Total January Estimated		13,000	1.946	$252,970	2.384	$309,970	$57,000
5								
6	**February Estimated**							
7	Economy	OS	5,000	2.211	$110,536	2.661	$133,036	$22,500
8	Total February Estimated		5,000	2.211	$110,536	2.661	$133,036	$22,500
9								
10	**March Estimated**							
11	Economy	OS	24,500	2.278	$558,000	2.747	$673,000	$115,000
12	Total March Estimated		24,500	2.278	$558,000	2.747	$673,000	$115,000
13								
14	**April Estimated**							
15	Economy	OS	27,500	2.268	$623,759	2.759	$758,759	$135,000
16	Total April Estimated		27,500	2.268	$623,759	2.759	$758,759	$135,000
17								
18	**May Estimated**							
19	Economy	OS	173,300	3.007	$5,211,422	3.534	$6,124,422	$913,000
20	Total May Estimated		173,300	3.007	$5,211,422	3.534	$6,124,422	$913,000
21								
22	**June Estimated**							
23	Economy	OS	228,000	2.721	$6,203,854	3.310	$7,546,854	$1,343,000
24	Total June Estimated		228,000	2.721	$6,203,854	3.310	$7,546,854	$1,343,000
25								
26	**6 Month Period**							
27	Economy	OS	471,300	2.750	$12,960,541	3.299	$15,546,041	$2,585,500
28	Total 6 Month Period		471,300	2.750	$12,960,541	3.299	$15,546,041	$2,585,500
29								
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32								
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FLORIDA POWER & LIGHT COMPANY
ECONOMY ENERGY PURCHASES

SCHEDULE: E9

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

Line No.	(1) PURCHASE FROM	(2) Type & Schedule	(3) Total KWH Purchased (000)	(4) Transaction Cost (cents/KWH)	(5) Total $ for Fuel Adj (Col(3) * Col(4))	(6) Cost if Generated (cents/KWH)	(7) Cost if Generated ($) (Col(3) * Col(6))	(8) Fuel Savings ($) (Col(7) - Col(5))
1								
2	**July Estimated**							
3	Economy	OS	313,000	2.691	$8,422,644	3.240	$10,140,644	$1,718,000
4	Total July Estimated		313,000	2.691	$8,422,644	3.240	$10,140,644	$1,718,000
5								
6	**August Estimated**							
7	Economy	OS	270,200	3.033	$8,195,879	3.889	$10,507,679	$2,311,800
8	Total August Estimated		270,200	3.033	$8,195,879	3.889	$10,507,679	$2,311,800
9								
10	**September Estimated**							
11	Economy	OS	133,000	2.742	$3,647,301	3.408	$4,533,301	$886,000
12	Total September Estimated		133,000	2.742	$3,647,301	3.408	$4,533,301	$886,000
13								
14	**October Estimated**							
15	Economy	OS	90,300	2.388	$2,156,221	2.866	$2,587,721	$431,500
16	Total October Estimated		90,300	2.388	$2,156,221	2.866	$2,587,721	$431,500
17								
18	**November Estimated**							
19	Economy	OS	31,800	2.058	$654,507	2.470	$785,507	$131,000
20	Total November Estimated		31,800	2.058	$654,507	2.470	$785,507	$131,000
21								
22	**December Estimated**							
23	Economy	OS	22,500	2.027	$456,049	2.460	$553,549	$97,500
24	Total December Estimated		22,500	2.027	$456,049	2.460	$553,549	$97,500
25								
26	**12 Month Period**							
27	Economy	OS	1,332,100	2.740	$36,493,143	3.352	$44,654,443	$8,161,300
28	Total 12 Month Period		1,332,100	2.740	$36,493,143	3.352	$44,654,443	$8,161,300
29								
30								
31	Note: Totals may not add due to rounding.							
32								
33								
34								
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39								

COMPANY: FLORIDA POWER & LIGHT COMPANY

	A	B		C (B - A)	
	CURRENT	PROPOSED JANUARY 17		DIFFERENCE $	%
BASE	$57.00	$67.00	(1)	$10.00	17.54%
FUEL	$21.73	$24.91		$3.18	14.63%
CONSERVATION	$1.86	$1.25	(2)	-$0.61	-32.80%
CAPACITY PAYMENT	$4.54	$2.98	(2)	-$1.56	-34.36%
NUCLEAR COST RECOVERY	$0.34	$0.00		-$0.34	-100.00%
ENVIRONMENTAL	$2.63	$2.41	(2)	-$0.22	-8.37%
STORM RESTORATION SURCHARGE	$1.44	$1.17	(3)	($0.27)	-18.75%
SUBTOTAL	$89.54	$99.72		$10.18	11.37%
GROSS RECEIPTS TAX	$2.30	$2.56		$0.26	11.30%
TOTAL	$91.84	$102.28		$10.44	11.37%

Notes:

(1) Reflects proposed base rate increase filed in Docket No. 160021-EI.

(2) Reflects 12 CP and 25% cost allocation methodology.

(3) Reflects Storm Charge effective September 1, 2016.

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

SCHEDULE: H1

Line No.	H1 Schedule	2014	2015	2016	2017	% Diff 2014 to 2015	% Diff 2016 to 2015	% Diff 2017 to 2016
1	**Fuel Cost of System Net Generation ($)**							
2	Heavy Oil	37,987,111	52,072,290	54,254,515	15,022,630	37.1%	4.2%	(72.3%)
3	Light Oil	23,732,404	28,986,203	29,855,078	23,784,696	22.1%	3.0%	(20.3%)
4	Coal	140,589,276	152,486,481	122,825,844	154,178,686	8.5%	(19.5%)	25.5%
5	Gas	3,084,986,796	2,834,167,759	2,380,989,998	2,623,390,342	(8.1%)	(16.0%)	10.2%
6	Nuclear	186,439,636	192,862,050	203,733,327	193,431,998	3.4%	5.6%	(5.1%)
7	**Total Fuel Cost of System Net Generation ($)**	3,473,735,223	3,260,574,784	2,791,658,762	3,009,808,353	(6.1%)	(14.4%)	7.8%
8								
9	**System Net Generation (MWh)**							
10	Heavy Oil	231,133	319,755	323,320	99,911	38.3%	1.1%	(69.1%)
11	Light Oil	127,625	138,639	191,149	220,923	8.6%	37.9%	15.6%
12	Coal	4,482,412	5,274,431	4,083,890	5,576,764	17.7%	(22.6%)	36.6%
13	Gas	79,211,239	85,793,538	84,222,028	81,741,079	8.3%	(1.8%)	(2.9%)
14	Nuclear	26,812,292	27,045,105	28,879,822	27,943,020	0.9%	6.8%	(3.2%)
15	Solar	68,265	67,686	200,260	482,211	(0.8%)	195.9%	140.8%
16	**Total System Net Generation (MWh)**	110,932,966	118,639,154	117,900,469	116,063,908	6.9%	(0.6%)	(1.6%)
17								
18	**Units of Fuel Burned (Unit)**							
19	Heavy Oil	409,022	563,755	610,688	211,962	37.8%	8.3%	(65.3%)
20	Light Oil	196,726	262,090	289,741	273,574	33.2%	10.6%	(5.6%)
21	Coal	2,595,295	3,141,190	2,371,015	3,368,153	21.0%	(24.5%)	42.1%
22	Gas	571,451,393	621,895,100	600,370,238	588,992,868	8.8%	(3.5%)	(1.9%)
23	Nuclear	297,789,701	299,536,675	317,993,383	302,416,541	0.6%	6.2%	(4.9%)
24	**Total Units of Fuel Burned (Unit)**							
25								
26	**BTU Burned (MMBTU)**							
27	Heavy Oil	2,584,010	3,557,645	3,872,764	1,356,556	37.7%	8.9%	(65.0%)
28	Light Oil	1,138,560	1,401,391	2,028,887	1,594,935	23.1%	44.8%	(21.4%)
29	Coal	48,114,249	56,411,948	45,192,067	60,416,512	17.2%	(19.9%)	33.7%
30	Gas	583,207,257	636,277,332	607,164,211	588,992,868	9.1%	(4.6%)	(3.0%)
31	Nuclear	297,789,701	299,536,675	317,993,383	302,416,541	0.6%	6.2%	(4.9%)
32	**Total BTU Burned (MMBTU)**	932,833,777	997,184,990	976,251,312	954,777,412	6.9%	(2.1%)	(2.2%)
33								
34	**Generation Mix (%MWH)**							
35	Heavy Oil	0.21%	0.27%	0.27%	0.09%	-	-	-
36	Light Oil	0.12%	0.12%	0.16%	0.19%	-	-	-
37	Coal	4.04%	4.45%	3.46%	4.80%	-	-	-
38	Gas	71.40%	72.31%	71.43%	70.43%	-	-	-
39	Nuclear	24.17%	22.80%	24.50%	24.08%	-	-	-
40	Solar	0.06%	0.06%	0.17%	0.42%	-	-	-
41	**Total Generation Mix (%MWH)**	100.00%	100.00%	100.00%	100.00%	-	-	-
42								
43	**Fuel Cost per Unit ($/Unit)**							
44	Heavy Oil	92.8731	92.3669	88.8417	70.8742	(0.5%)	(3.8%)	(20.2%)
45	Light Oil	120.6368	110.5964	103.0406	86.9407	(8.3%)	(6.8%)	(15.6%)
46	Coal	54.1708	48.5442	51.8031	45.7754	(10.4%)	6.7%	(11.6%)
47	Gas	5.3985	4.5573	3.9659	4.4540	(15.6%)	(13.0%)	12.3%
48	Nuclear	0.6261	0.6439	0.6407	0.6396	2.8%	(0.5%)	(0.2%)
49								

Line No.	H1 Schedule	2014	2015	2016	2017	% Diff 2014 to 2015	% Diff 2016 to 2015	% Diff 2017 to 2016
1	**Fuel Cost per MMBTU ($/MMBTU)**							
2	Heavy Oil	14.7008	14.6367	14.0092	11.0741	(0.4%)	(4.3%)	(21.0%)
3	Light Oil	20.8442	20.6839	14.7150	14.9126	(0.8%)	(28.9%)	1.3%
4	Coal	2.9220	2.7031	2.7179	2.5519	(7.5%)	0.5%	(6.1%)
5	Gas	5.2897	4.4543	3.9215	4.4540	(15.8%)	(12.0%)	13.6%
6	Nuclear	0.6261	0.6439	0.6407	0.6396	2.8%	(0.5%)	(0.2%)
7	**Total Fuel Cost per MMBTU ($/MMBTU)**	3.7239	3.2698	2.8596	3.1524	(12.2%)	(12.5%)	10.2%
8								
9	**BTU Burned per KWH (BTU/KWH)**							
10	Heavy Oil	11,180	11,126	11,978	13,578	(0.5%)	7.7%	13.4%
11	Light Oil	8,921	10,108	10,614	7,219	13.3%	5.0%	(32.0%)
12	Coal	10,734	10,695	11,066	10,834	(0.4%)	3.5%	(2.1%)
13	Gas	7,363	7,416	7,209	7,206	0.7%	(2.8%)	(0.0%)
14	Nuclear	11,106	11,075	11,011	10,823	(0.3%)	(0.6%)	(1.7%)
15	**Total BTU Burned per KWH (BTU/KWH)**	8,409	8,405	8,280	8,226	(0.0%)	(1.5%)	(0.7%)
16								
17	**Generated Fuel Cost per KWH (cents/KWH)**							
18	Heavy Oil	16.4352	16.2851	16.7804	15.0360	(0.9%)	3.0%	(10.4%)
19	Light Oil	18.5954	20.9077	15.6187	10.7661	12.4%	(25.3%)	(31.1%)
20	Coal	3.1365	2.8911	3.0076	2.7647	(7.8%)	4.0%	(8.1%)
21	Gas	3.8946	3.3035	2.8270	3.2094	(15.2%)	(14.4%)	13.5%
22	Nuclear	0.6954	0.7131	0.7055	0.6922	2.6%	(1.1%)	(1.9%)
23	**Total Generated Fuel Cost per KWH (cents/KWH)**	3.1314	2.7483	2.3678	2.5932	(12.2%)	(13.8%)	9.5%
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(Continued from Sheet No. 10.100)

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST

For informational purposes only, the estimated incremental As-Available Energy costs for the next two periods are as follows. In addition, As-Available Energy cost payments will include .0057¢/kWh for variable operation and maintenance expenses.

Applicable Period	On-Peak ¢/KWH	Off-Peak ¢/KWH	Average ¢/KWH
January 1, 2017 – December 31, 2017	2.97	2.65	2.73
January 1, 2018 – December 31, 2018	2.87	2.50	2.59

A MW block size ranging from 39 MW to 44 MW has been used to calculate the estimated avoided energy cost.

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	1.0107
Secondary Voltage Delivery	1.0279

For informational purposes the Company's projected annual generation mix and fuel prices are as follows:

PROJECTED ANNUAL GENERATION MIX AND FUEL PRICES

	Energy Sources % by Fuel Type Generation by Type						Price by Fuel Type				
Year	Gas	Oil	Coal	Nuclear	Purchased Power	Solar	Gas	Oil	Coal	Nuclear	Solar
2016	67.8	1.0	3.3	23.9	3.3	0.1	2.57	8.97	2.89	0.65	0.00
2017	70.6	0.0	2.3	23.8	2.7	0.5	2.86	9.77	2.92	0.64	0.00
2018	70.7	0.0	2.2	23.6	2.9	0.5	2.98	10.70	2.98	0.61	0.00
2019	69.9	0.1	2.6	24.0	2.9	0.5	3.69	13.44	3.07	0.63	0.00
2020	71.2	0.0	2.4	23.4	1.9	1.0	3.77	13.73	3.16	0.64	0.00
2021	70.2	0.0	2.8	23.2	2.6	1.0	4.44	16.67	3.24	0.66	0.00
2022	69.6	0.0	2.8	23.6	2.8	1.0	4.70	17.21	3.33	0.67	0.00
2023	69.9	0.0	2.7	23.0	3.1	1.0	5.03	17.93	3.42	0.69	0.00
2024	69.9	0.0	2.9	22.9	3.2	1.0	5.62	19.58	3.50	0.71	0.00
2025	69.9	0.0	2.7	23.1	3.2	1.0	5.61	20.34	3.58	0.73	0.00

NOTE: - Amounts may not add to 100% due to rounding.
- The Company's forecasts are for illustrative purposes, and are subject to frequent revisions.

(Continued on Sheet No. 10.102)

(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	0.066%
Distribution Equipment	0.158%
Transmission Equipment	0.107%

D. Taxes and Assessments

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

TERMS OF SERVICE

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

(Continue on Sheet No. 10.104)

APPENDIX III
CAPACITY COST RECOVERY
PROPOSED COST ALLOCATION METHODOLOGY
12 CP AND 25%

JANUARY 2017 THROUGH DECEMBER 2017 FACTORS

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 23
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT & SUPPLEMENTAL)*Notice of Adoption of Terry J. Keith's testimony and exhibits by Renae B. Deaton, filed on October 3, 2016, (FPSC DN #07930-16).
DESCRIPTION: *R. B. Deaton TJK-6

TJK-6
DOCKET NO. 160001-EI
FPL WITNESS: TERRY J. KEITH
EXHIBIT _____
PAGES 1-23
SEPTEMBER 2, 2016

APPENDIX III
CAPACITY COST RECOVERY
2017 FACTORS JAN 2017 THROUGH DEC 2017
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
FOR THE ACTUAL/ESTIMATED PERIOD OF: JANUARY 2016 THROUGH DECEMBER 2016

Line No.	(1)	(2) January Actual	(3) February Actual	(4) March Actual	(5) April Actual	(6) May Actual	(7) June Actual	(8) July Actual	(9) August Estimated	(10) September Estimated	(11) October Estimated	(12) November Estimated	(13) December Estimated	(14) Total
1	Payments to Non-cogenerators	$5,797,708	$5,882,677	$6,940,701	$6,065,010	$6,320,975	$6,751,736	$6,247,636	$6,293,112	$6,293,112	$6,117,757	$6,117,757	$6,117,757	$74,945,939
2	Payments to Co-generators	$7,865,875	$7,859,530	$7,862,703	$7,153,752	$8,494,181	$7,838,135	$7,840,415	$7,875,618	$7,875,618	$7,875,618	$7,875,618	$7,875,618	$94,292,684
3	Cedar Bay Transaction - Regulatory Asset - Amortization and Return	$9,582,935	$9,552,678	$9,522,421	$9,492,164	$9,461,907	$9,431,637	$9,416,290	$9,385,886	$9,355,482	$9,325,078	$9,294,675	$9,264,271	$113,085,422
4	Cedar Bay Transaction - Regulatory Liability - Amortization and Return	($116,035)	($115,543)	($115,052)	($114,560)	($114,068)	($113,577)	($113,327)	($112,833)	($112,339)	($111,845)	($111,351)	($110,857)	($1,361,389)
5	SJRPP Suspension Accrual	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($9,083,880)
6	Return on SJRPP Suspension Liability	($215,495)	($209,605)	($203,714)	($197,824)	($191,933)	($186,043)	($181,026)	($175,107)	($169,188)	($163,269)	($157,350)	($151,431)	($2,201,987)
7	Incremental Plant Security Costs O&M	$3,384,335	$2,770,804	$3,067,222	$2,869,562	$2,644,814	$2,469,998	$2,508,789	$3,338,845	$3,312,175	$4,246,320	$3,798,490	$6,183,323	$40,594,676
8	Incremental Plant Security Costs Capital	$152,222	$154,484	$157,074	$160,110	$162,740	$165,515	$168,895	$184,486	$200,594	$203,511	$206,644	$210,201	$2,126,476
9	Incremental Nuclear NRC Compliance Costs O&M	$39,528	$284,430	$215,058	$242,810	$287,540	$183,519	$245,834	$269,562	$190,909	$96,443	$90,909	$917,399	$3,063,940
10	Incremental Nuclear NRC Compliance Costs Capital	$599,108	$614,544	$627,540	$674,337	$714,494	$717,277	$721,708	$721,316	$721,047	$720,732	$719,951	$719,488	$8,271,544
11	Transmission of Electricity by Others	$1,846,023	$1,886,685	$1,827,304	$2,218,116	$2,159,231	$6,113	($1,905,037)	$0	$0	$0	$0	$0	$8,038,435
12	Transmission Revenues from Capacity Sales	($1,085,665)	($637,884)	($991,779)	($894,359)	($517,100)	($384,728)	($308,957)	($230,750)	($259,575)	($207,050)	($229,800)	($327,800)	($6,075,446)
13	Total (Lines 1 through 12)	$27,093,550	$27,285,809	$28,152,487	$26,912,126	$28,665,791	$26,122,593	$23,884,230	$26,793,145	$26,650,846	$27,346,306	$26,848,553	$29,940,979	$325,696,415
14	Jurisdictional Separation Factor [a]	94.67506%	94.67506%	94.67506%	94.67506%	94.67506%	94.67506%	94.67506%	94.67506%	94.67506%	94.67506%	94.67506%	94.67506%	N/A
15	Jurisdictional CCR Charges	$25,650,835	$25,832,856	$26,653,384	$25,479,072	$27,139,355	$24,731,580	$22,612,409	$25,366,426	$25,231,704	$25,890,132	$25,418,883	$28,346,640	$308,353,276
16	Nuclear Cost Recovery Costs	$2,086,094	$3,104,524	$5,127,776	$2,295,622	$2,606,357	$3,156,370	$2,027,703	$2,065,414	$2,962,031	$1,959,644	$1,974,012	$4,884,069	$34,249,615
17	Jurisdictional CCR Charges	$27,736,929	$28,937,381	$31,781,160	$27,774,694	$29,745,711	$27,887,950	$24,640,111	$27,431,841	$28,193,735	$27,849,776	$27,392,895	$33,230,709	$342,602,891
18	CCR Revenues (Net of Revenue Taxes)	$26,963,403	$23,724,517	$25,032,700	$26,889,453	$28,090,196	$31,774,952	$35,451,122	$33,661,147	$32,913,149	$30,353,623	$26,452,278	$26,148,260	347,454,801
19	Prior Period True-up Provision	$395,679	$395,679	$395,679	$395,679	$395,679	$395,679	$395,679	$395,679	$395,679	$395,679	$395,679	$395,679	$4,748,145
20	CCR Revenues Applicable to Current Period (Net of Revenue Taxes)	$27,359,082	$24,120,196	$25,428,379	$27,285,132	$28,485,875	$32,170,631	$35,846,801	$34,056,826	$33,308,828	$30,749,301	$26,847,957	$26,543,939	$352,202,946
21	True-up Provision for Month - Over/(Under) Recovery (Line 20 - Line 17)	($377,847)	($4,817,185)	($6,352,781)	($489,562)	($1,259,837)	$4,282,681	$11,206,690	$6,624,985	$5,115,093	$2,899,526	($544,938)	($6,686,770)	$9,600,055
22	Interest Provision for Month	$3,433	$2,498	$477	($807)	($1,095)	($814)	$1,589	$4,740	$6,703	$8,000	$8,283	$6,848	$39,854
23	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	$4,748,145	$3,978,052	($1,232,314)	($7,980,296)	($8,866,344)	($10,522,955)	($6,636,767)	$4,175,833	$10,409,880	$15,135,997	$17,647,844	$16,715,509	$4,748,145
24	Deferred True-up - Over/(Under) Recovery	$5,938,824	$5,938,824	$5,938,824	$5,938,824	$5,938,824	$5,938,824	$5,938,824	$5,938,824	$5,938,824	$5,938,824	$5,938,824	$5,938,824	$5,938,824
25	Prior Period True-up Provision - Collected/(Refunded) this Month	($395,679)	($395,679)	($395,679)	($395,679)	($395,679)	($395,679)	($395,679)	($395,679)	($395,679)	($395,679)	($395,679)	($395,679)	($4,748,145)
26	End of Period True-up - Over/(Under) Recovery (Sum of Lines 21 through 25)	$9,916,876	$4,706,510	($2,041,472)	($2,927,520)	($4,584,131)	($697,943)	$10,114,657	$16,348,704	$21,074,821	$23,586,668	$22,654,333	$15,578,733	$15,578,733
27														
28	[a] As approved on Order No. PSC-15-0586-FOF-EI.													
29														
30														
31														
32														
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35														
36														
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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
PROJECTED CAPACITY PAYMENTS
ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

Line No.	(1)	(2) January Estimated	(3) February Estimated	(4) March Estimated	(5) April Estimated	(6) May Estimated	(7) June Estimated	(8) July Estimated	(9) August Estimated	(10) September Estimated	(11) October Estimated	(12) November Estimated	(13) December Estimated	(14) Total
1	Capacity Payments To Non-Cogenerators	$6,165,633	$6,165,633	$6,165,633	$6,165,633	$6,165,633	$6,206,033	$6,206,033	$6,206,033	$6,206,033	$5,260,418	$5,260,418	$5,260,418	$71,433,553
2	Capacity Payments To Cogenerators	$7,792,719	$7,792,719	$7,792,719	$7,792,719	$7,792,719	$7,792,719	$7,792,719	$7,792,719	$7,792,719	$7,792,719	$7,792,719	$7,792,719	$93,512,628
3	Cedar Bay Transaction - Regulatory Asset - Amortization and Return	$11,036,114	$10,999,776	$10,963,439	$10,927,101	$10,890,763	$10,854,425	$10,818,087	$10,781,749	$10,745,411	$10,709,073	$10,672,736	$10,636,398	$130,035,072
4	Cedar Bay Transaction - Regulatory Liability - Amortization and Return	($110,363)	($109,869)	($109,375)	($108,881)	($108,387)	($107,893)	($107,399)	($106,905)	($106,411)	($105,917)	($105,423)	($104,929)	($1,291,750)
5	SJRPP Suspension Accrual	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($9,083,880)
6	Return Requirements On SJRPP Suspension Liability	($145,512)	($139,593)	($133,674)	($127,756)	($121,837)	($115,918)	($109,999)	($104,080)	($98,161)	($92,242)	($86,323)	($80,404)	($1,355,497)
7	Incremental Plant Security Costs O&M	$3,473,475	$2,913,424	$3,413,885	$3,611,563	$2,954,626	$3,176,849	$3,394,487	$2,904,413	$3,079,020	$3,418,743	$3,226,839	$3,638,259	$39,205,584
8	Incremental Plant Security Costs Capital	$213,189	$215,760	$220,450	$227,413	$235,054	$242,816	$250,422	$258,523	$266,548	$273,929	$281,068	$308,800	2,993,970
9	Incremental Nuclear NRC Compliance Costs O&M	$109,401	$109,401	$181,901	$109,401	$109,401	$171,901	$109,401	$109,401	$171,901	$109,401	$59,401	$121,901	$1,472,810
10	Incremental Nuclear NRC Compliance Costs Capital	$719,008	$718,108	$717,207	$716,306	$715,406	$714,505	$713,604	$712,704	$711,803	$710,902	$710,002	$709,101	$8,568,656
11	Transmission Revenues From Capacity Sales	($1,392,948)	($1,120,324)	($683,816)	($481,000)	($269,125)	($185,125)	($210,125)	($210,125)	($253,125)	($196,250)	($283,500)	($497,000)	($5,782,463)
12	System Total	$27,103,727	$26,788,045	$27,771,378	$28,075,510	$27,607,263	$27,993,323	$28,100,242	$27,587,442	$27,758,749	$27,123,787	$26,770,946	$27,028,272	$329,708,684
13	Jurisdictional % *													95.04658%
14	Jurisdictionalized Capacity Payments													$313,376,833
15	2015 FINAL TRUE-UP -- (Over)/Under Recovery													($5,938,824)
16	2016 ACT/EST TRUE-UP -- (Over)/Under Recovery													($9,639,909)
17	Nuclear Cost Recovery Clause													$0
18	Cape Canaveral GBRA True-up													($1,890,528)
19	Total (Lines 14+15+16+17+18)													$295,907,572
20	Revenue Tax Multiplier													1.00072
21	Total Recoverable Capacity Payments													$296,120,626
22														
23	*Calculation of Jurisdictional %													
24	.....AVG. 12CP													
25	.....AT GEN (MW).....%													
26	FPSC.....19,893.365.....95.04658%													
27	FERC.....1,036.757.....4.95342%													
28	TOTAL.....20,930.121.....100.00000%													
29														
30	* Based on 2017 Estimated Data													
31	Totals may not add up due to rounding.													
32														
33														
34														
35														
36														
37														
38														
39														

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY DEMAND ALLOCATION % BY RATE CLASS
ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
RATE SCHEDULE	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) [g]	Percentage of Sales at Generation (%) [h]	Percentage of Demand at Generation (%) [i]
RS1/RTR1	59.146%	57,063,506,058	11,013,646	1.06430156	1.04862829	59,838,406,779	11,721,841	53.21566%	58.92337%
GS1/GST1	65.027%	5,971,311,587	1,048,260	1.06430156	1.04862829	6,261,686,259	1,115,665	5.56866%	5.60823%
GSD1/GSDT1/HLFT1	72.765%	25,836,330,536	4,053,251	1.06421646	1.04856471	27,091,064,436	4,313,536	24.09270%	21.68329%
OS2	92.223%	10,793,313	1,336	1.05687787	1.02669200	11,081,408	1,412	0.00985%	0.00710%
GSLD1/GSLDT1/CS1/CST1/HLFT2	73.257%	10,511,832,443	1,638,034	1.06313919	1.04778551	11,014,145,717	1,741,458	9.79513%	8.75396%
GSLD2/GSLDT2/CS2/CST2/HLFT3	87.653%	2,516,449,511	327,730	1.05469612	1.04113164	2,619,955,206	345,656	2.32999%	1.73754%
GSLD3/GSLDT3/CS3/CST3	86.088%	172,996,790	22,940	1.02180107	1.01700518	175,938,632	23,440	0.15647%	0.11783%
SST1T	107.395%	89,667,754	9,531	1.02180107	1.01700518	91,192,570	9,739	0.08110%	0.04895%
SST1D1/SST1D2/SST1D3	78.275%	11,856,926	1,729	1.03476555	1.02669200	12,173,411	1,789	0.01083%	0.00899%
CILC D/CILC G	87.305%	2,789,895,442	364,790	1.05313565	1.04053446	2,902,982,347	384,173	2.58169%	1.93116%
CILC T	91.242%	1,508,389,554	188,718	1.02180107	1.01700518	1,534,039,990	192,832	1.36426%	0.96933%
MET	71.670%	91,208,296	14,528	1.03476555	1.02669200	93,642,828	15,033	0.08328%	0.07557%
OL1/SL1/PL1/SL1M	586.798%	658,751,104	12,815	1.06430156	1.04862829	690,785,044	13,639	0.61433%	0.06856%
SL2, GSCU1,SL2M	95.157%	103,004,444	12,357	1.06430156	1.04862829	108,013,374	13,152	0.09606%	0.06611%
TOTAL		107,335,993,758	18,709,665			112,445,108,001	19,893,365	100.00000%	100.00000%

[a] AVG 12 CP load factor based on 2013-2015 load research data and 2017 projections.

[b] Projected kwh sales for the period January 2017 through December 2017.

[c] Calculated: Col(3)/(8760 hours * Col(2))

[d] Based on 2016 demand losses.

[e] Based on 2016 energy losses.

[f] Col(3) * Col(6)

[g] Col(4) * Col(5)

[h] Col(7) / Total for Col(7)

[i] Col(8) / Total for Col(8)

Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR
12CP AND 25% COS ALLOCATION
ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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]
RS1/RTR1	53.21566%	58.92337%	$39,395,637	$130,863,185	$170,258,822	57,063,506,058	-	-	-	0.00298	-	-
GS1/GST1	5.56866%	5.60823%	$4,122,488	$12,455,334	$16,577,822	5,971,311,587	-	-	-	0.00278	-	-
GSD1/GSDT1/HLFT1	24.09270%	21.68329%	$17,835,865	$48,156,526	$65,992,390	25,836,330,536	50.15375%	70,567,469	0.94	-	-	-
OS2	0.00985%	0.00710%	$7,296	$15,764	$23,059	10,793,313	-	-	-	0.00214	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	9.79513%	8.75396%	$7,251,351	$19,441,721	$26,693,072	10,511,832,443	56.71170%	25,391,181	1.05	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	2.32999%	1.73754%	$1,724,892	$3,858,915	$5,583,807	2,516,449,511	65.79207%	5,239,524	1.07	-	-	-
GSLD3/GSLDT3/CS3/CST3	0.15647%	0.11783%	$115,832	$261,687	$377,519	172,996,790	68.69783%	344,963	1.09	-	-	-
SST1T	0.08110%	0.04895%	$60,038	$108,724	$168,762	89,667,754	11.31969%	1,085,123	-	-	$0.13	$0.06
SST1D1/SST1D2/SST1D3	0.01083%	0.00899%	$8,015	$19,974	$27,988	11,856,926	29.68376%	54,718	-	-	$0.13	$0.06
CILC D/CILC G	2.58169%	1.93116%	$1,911,228	$4,288,930	$6,200,158	2,789,895,442	74.14313%	5,154,590	1.20	-	-	-
CILC T	1.36426%	0.96933%	$1,009,961	$2,152,788	$3,162,750	1,508,389,554	76.33683%	2,706,802	1.17	-	-	-
MET	0.08328%	0.07557%	$61,651	$167,830	$229,481	91,208,296	64.64301%	193,281	1.19	-	-	-
OL1/SL1/PL1/SL1M	0.61433%	0.06856%	$454,790	$152,267	$607,057	658,751,104	-	-	-	0.00092	-	-
SL2, GSCU1,SL2M	0.09606%	0.06611%	$71,112	$146,825	$217,937	103,004,444	-	-	-	0.00212	-	-
TOTAL			$74,030,156	$222,090,469	$296,120,626	107,335,993,758		110,737,652				

[a] Obtained from Page 2, Col(9)

[b] Obtained from Page 2, Col(10)

[c] (Total Capacity Costs/13) * Col(2)

[d] (Total Capacity Costs/13 * 12) * Col(3)

[e] Col(4) + Col(5)

[f] Projected kwh sales for the period January 2017 through December 2017.

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

[h] Col(7) / (Col(8) *730)

[i] Col(6) / Col(9)

[j] Col(6) / Col(7)

[k] RDC = Reservation Demand Charge - (Total Col 6)/(Page 2 Total Col 8)(.10)(Page 2 Col 5)/12 Months

[l] SDD = Sum of Daily Demand Charge - (Total Col 6)/(Page 2 Total Col 8)/(21 onpeak days)(Page 2 Col 5)/12 Months

Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

Totals may not add due to rounding.

Florida Power & Light Company
Capacity Cost Recovery Clause
For the Period January through June 2016

Return on Capital Investments, Depreciation and Taxes
Incremental Security
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$212,241	$392,463	$354,184	$353,875	($76,791)	$449,511	$1,685,484
	b. Clearings to Plant		$7,569	$6,067	$2,001	$49,227	$319,244	$860	$384,967
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other		$0	$0	$0	$0	$0	$0	$0
2.	Plant-In-Service/Depreciation Base	$4,210,542	$4,218,111	$4,224,178	$4,226,178	$4,275,405	$4,594,649	$4,595,509	n/a
3.	Less: Accumulated Depreciation	$105,341	$125,539	$145,751	$165,772	$186,033	$206,571	$227,349	n/a
4.	CWIP - Non Interest Bearing	$12,761,654	$12,973,895	$13,366,358	$13,720,543	$14,074,418	$13,997,627	$14,447,138	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$16,866,855	$17,066,467	$17,444,785	$17,780,949	$18,163,790	$18,385,705	$18,815,298	n/a
6.	Average Net Investment		$16,966,661	$17,255,626	$17,612,867	$17,972,369	$18,274,748	$18,600,501	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (a)		$110,951	$112,841	$115,177	$117,528	$119,505	$121,635	$697,637
	b. Debt Component (Line 6 x debt rate x 1/12) (b)		$21,073	$21,431	$21,875	$22,322	$22,697	$23,102	$132,500
8.	Investment Expenses								
	a. Depreciation		$20,198	$20,212	$20,022	$20,261	$20,538	$20,778	$122,009
	b. Amortization		$0	$0	$0	$0	$0	$0	$0
	c. Other		$0	$0	$0	$0	$0	$0	$0
9.	Total System Recoverable Expenses (Lines 11 & 12)		$152,222	$154,484	$157,074	$160,110	$162,740	$165,515	$952,145

Notes:

(a) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component is 4.8201%, which is based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(b) The Debt Component is 1.4904%, which is based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

Totals may not add due to rounding.

Florida Power & Light Company
Capacity Cost Recovery Clause
For the Period July through December 2016

Return on Capital Investments, Depreciation and Taxes
Incremental Security
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$275,123	($12,885,239)	$403,214	$399,822	$484,442	$232,951	($9,404,204)
	b. Clearings to Plant		$743	$13,378,710	$25,980	$4,020	$4,406	$235,074	$14,033,900
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other		$0	$0	$0	$0	$0	$0	$0
2.	Plant-In-Service/Depreciation Base (a)	$4,595,509	$4,596,252	$17,974,962	$18,000,942	$18,004,962	$18,009,368	$18,244,442	n/a
3.	Less: Accumulated Depreciation	$227,349	$248,129	$281,703	$328,092	$374,502	$420,920	$467,516	n/a
4.	CWIP - Non Interest Bearing	$14,447,138	$14,722,261	$1,837,022	$2,240,236	$2,640,058	$3,124,500	$3,357,450	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$18,815,298	$19,070,384	$19,530,281	$19,913,087	$20,270,518	$20,712,948	$21,134,376	n/a
6.	Average Net Investment		$18,942,841	$19,300,333	$19,721,684	$20,091,802	$20,491,733	$20,923,662	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (a)		$126,125	$128,505	$131,311	$133,775	$136,438	$139,314	$1,493,106
	b. Debt Component (Line 6 x debt rate x 1/12) (b)		$21,991	$22,406	$22,895	$23,325	$23,789	$24,290	$271,195
8.	Investment Expenses								
	a. Depreciation		$20,779	$33,574	$46,388	$46,411	$46,417	$46,597	$362,175
	b. Amortization		$0	$0	$0	$0	$0	$0	$0
	c. Other		$0	$0	$0	$0	$0	$0	$0
9.	Total System Recoverable Expenses (Lines 11 & 12)		$168,895	$184,486	$200,594	$203,511	$206,644	$210,201	$2,126,476

Notes:

(a) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component is 4.9078%, which is based on the May 2016 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(b) The Debt Component is 1.3931%, which is based on the May 2016 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

Totals may not add due to rounding.

Florida Power & Light Company
Capacity Cost Recovery Clause
For the Period January through June 2017

Return on Capital Investments, Depreciation and Taxes
Incremental Security
(in Dollars)

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$344,505	$406,740	$886,297	$988,364	$1,059,520	$1,019,520	$4,704,946
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other		$0	$0	$0	$0	$0	$0	$0
2.	Plant-In-Service/Depreciation Base	$18,244,442	$18,244,442	$18,244,442	$18,244,442	$18,244,442	$18,244,442	$18,244,442	n/a
3.	Less: Accumulated Depreciation	$467,516	$514,289	$561,062	$607,835	$654,608	$701,382	$748,155	n/a
4.	CWIP - Non Interest Bearing	$3,357,450	$3,701,955	$4,108,695	$4,994,992	$5,983,356	$7,042,876	$8,062,396	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$21,134,376	$21,432,108	$21,792,075	$22,631,599	$23,573,190	$24,585,937	$25,558,684	n/a
10.	Average Net Investment		$21,283,242	$21,612,091	$22,211,837	$23,102,394	$24,079,563	$25,072,310	n/a
11.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (a)		$141,708	$143,898	$147,891	$153,820	$160,327	$166,936	$914,580
	b. Debt Component (Line 6 x debt rate x 1/12) (b)		$24,708	$25,089	$25,786	$26,820	$27,954	$29,106	$159,463
12.	Investment Expenses								
	a. Depreciation		$46,773	$46,773	$46,773	$46,773	$46,773	$46,773	$280,638
	b. Amortization		$0	$0	$0	$0	$0	$0	$0
	c. Other		$0	$0	$0	$0	$0	$0	$0
13.	Total System Recoverable Expenses (Lines 11 & 12)		$213,189	$215,760	$220,450	$227,413	$235,054	$242,816	$1,354,681

Notes [a] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component is 4.9078%, which is based on the May 2016 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.
[b] The Debt Component is 1.3931%, which is based on the May 2016 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

Totals may not add due to rounding.

Florida Power & Light Company
Capacity Cost Recovery Clause
For the Period July through December 2017

Return on Capital Investments, Depreciation and Taxes
Incremental Security
(in Dollars)

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$1,019,520	$1,146,012	$1,000,353	$981,153	$938,348	($7,823,959)	$1,966,373
	b. Clearings to Plant		$0	$0	$0	$0	$0	$8,729,044	$8,729,044
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other		$0	$0	$0	$0	$0	$0	$0
2.	Plant-In-Service/Depreciation Base (a)	$18,244,442	$18,244,442	$18,244,442	$18,244,442	$18,244,442	$18,244,442	$26,973,486	n/a
3.	Less: Accumulated Depreciation	$748,155	$794,928	$841,701	$888,474	$935,247	$982,020	$1,049,765	n/a
4.	CWIP - Non Interest Bearing	$8,062,396	$9,081,916	$10,227,928	$11,228,281	$12,209,434	$13,147,782	$5,323,823	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$25,558,684	$26,531,431	$27,630,670	$28,584,250	$29,518,629	$30,410,204	$31,247,544	n/a
6.	Average Net Investment		$26,045,057	$27,081,050	$28,107,460	$29,051,440	$29,964,417	$30,828,874	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (a)		$173,413	$180,311	$187,145	$193,430	$199,509	$205,265	$2,053,654
	b. Debt Component (Line 6 x debt rate x 1/12) (b)		$30,236	$31,438	$32,630	$33,726	$34,786	$35,789	$358,068
8.	Investment Expenses								
	a. Depreciation		$46,773	$46,773	$46,773	$46,773	$46,773	$67,746	$582,249
	b. Amortization		$0	$0	$0	$0	$0	$0	$0
	c. Other		$0	$0	$0	$0	$0	$0	$0
13.	Total System Recoverable Expenses (Lines 11 & 12)		$250,422	$258,523	$266,548	$273,929	$281,068	$308,800	$2,993,970

Notes:

(a) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component is 4.9078%, which is based on the May 2016 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(b) The Debt Component is 1.3931%, which is based on the May 2016 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

Totals may not add due to rounding.

Florida Power & Light Company
Capacity Cost Recovery Clause
For the Period January through June 2016

Return on Capital Investments, Depreciation and Taxes
Incremental Nuclear NRC Compliance
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$1,703,761	$1,304,227	$1,592,068	($15,688,836)	$0	$0	($11,088,779)
	b. Clearings to Plant		$709,947	$263,841	$316,247	$19,570,169	$360,577	$505,897	$21,726,678
	c. Clearings to Plant - Base		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other		$0	$0	$0	$0	$0	($2,961)	($2,961)
2.	Incremental Plant-In-Service/Depreciation	$52,069,931	$52,779,878	$53,043,719	$53,359,966	$72,930,135	$73,290,712	$73,796,609	
3.	Less: Accumulated Depreciation	$554,156	$657,122	$760,835	$864,827	$993,997	$1,147,922	$1,299,486	
4.	CWIP - Non Interest Bearing	$11,089,331	$12,793,092	$14,097,320	$15,689,388	$552	$552	$552	
5.	Net Investment (Lines 2 - 3 + 4)	$62,605,106	$64,915,849	$66,380,204	$68,184,528	$71,936,691	$72,143,343	$72,497,675	n/a
6.	Total Estimated Capital Expenditures Included in Base Rates (b)		$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	
7.	Base Rate Capital Expenditures Closed to Plant-in-Service (c)		$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	
8.	Remaining Amount Included in Base Rates (Lines 6 - 7)		$0	$0	$0	$0	$0	$0	
9.	Adjusted Net Investment (Lines 5 - 8)	$62,605,106	$64,915,849	$66,380,204	$68,184,528	$71,936,691	$72,143,343	$72,497,675	
10.	Average Net Investment		$63,760,477	$65,648,027	$67,282,366	$70,060,609	$72,040,017	$72,320,509	n/a
11.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (d)		$416,953	$429,296	$439,983	$458,151	$471,095	$472,930	$2,688,408
	b. Debt Component (Line 6 x debt rate x 1/12) (e)		$79,191	$81,535	$83,565	$87,015	$89,474	$89,822	$510,601
12.	Investment Expenses								
	a. Depreciation		$102,965	$103,714	$103,991	$129,170	$153,925	$154,525	$748,291
	b. Amortization		$0	$0	$0	$0	$0	$0	$0
	c. Other		$0	$0	$0	$0	$0	$0	$0
13.	Total System Recoverable Expenses (Lines 11 & 12)		$599,108	$614,544	$627,540	$674,337	$714,494	$717,277	$3,947,300

Notes:

[a] Represents nuclear NRC compliance plant-in-service in excess of the total estimated capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI) on line 6.

[b] Represents forecasted nuclear NRC compliance capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI).

[c] Represents base rate recoverable nuclear NRC compliance capital expenditures closed to plant-in-service.

[d] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component is 4.8201%, which is based on the May 2015 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[e] The Debt Component is 1.4904%, which is based on the May 2015 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

Totals may not add due to rounding.

Florida Power & Light Company
Capacity Cost Recovery Clause
For the Period June through December 2016

Return on Capital Investments, Depreciation and Taxes
Incremental Nuclear NRC Compliance
(in Dollars)

Line		Beginning of Period Amount	July Actual	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
a.	Expenditures/Additions		$0	$20,000	$30,000	$30,000	$40,000	$55,965	($10,912,814)
b.	Clearings to Plant		$100,109	$48,537	$111,103	$30,308	$3,555	$77,332	$22,097,622
c.	Clearings to Plant - Base		$0	$0	$0	$0	$0	$0	$0
d.	Retirements		$0	$0	$0	$0	$0	$0	$0
e.	Other		$0	$0	$0	$0	$0	$0	($2,961)
2.	Incremental Plant-In-Service/Depreciation Base (a)	$73,796,609	$73,896,718	$73,945,255	$74,056,358	$74,086,666	$74,090,221	$74,167,553	n/a
3.	Less: Accumulated Depreciation	$1,299,486	$1,454,542	$1,609,761	$1,765,105	$1,920,561	$2,076,046	$2,231,592	n/a
4.	CWIP - Non Interest Bearing	$552	$552	$20,552	$50,552	$80,552	$120,552	$176,517	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$72,497,675	$72,442,728	$72,356,047	$72,341,806	$72,246,657	$72,134,727	$72,112,479	n/a
6.	Total Estimated Capital Expenditures Included in Base Rates (b)	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	
7.	Base Rate Capital Expenditures Closed to Plant-in-Service (c)	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	
8.	Remaining Amount Included in Base Rates (Lines 6 - 7)	$0	$0	$0	$0	$0	$0	$0	
9.	Adjusted Net Investment (Lines 5 - 8)	$72,497,675	$72,442,728	$72,356,047	$72,341,806	$72,246,657	$72,134,727	$72,112,479	
10.	Average Net Investment		$72,470,202	$72,399,388	$72,348,926	$72,294,232	$72,190,692	$72,123,603	n/a
11.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (d)		$482,521	$482,050	$481,714	$481,350	$480,660	$480,213	$5,576,916
b.	Debt Component (Line 6 x debt rate x 1/12) (e)		$84,131	$84,048	$83,990	$83,926	$83,806	$83,728	$1,014,231
12.	Investment Expenses								
a.	Depreciation		$155,056	$155,218	$155,344	$155,457	$155,485	$155,546	$1,680,397
b.	Amortization		$0	$0	$0	$0	$0	$0	$0
c.	Other		$0	$0	$0	$0	$0	$0	$0
13.	Total System Recoverable Expenses (Lines 11 & 12)		$721,708	$721,316	$721,047	$720,732	$719,951	$719,488	$8,271,544

Notes:

(a) Represents nuclear NRC compliance plant-in-service in excess of the total estimated capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI) on line 6.

(b) Represents forecasted nuclear NRC compliance capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI).

(c) Represents base rate recoverable nuclear NRC compliance capital expenditures closed to plant-in-service.

(d) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component is 4.9078%, which is based on the May 2016 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(e) The Debt Component is 1.3931%, which is based on the May 2016 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

Totals may not add due to rounding.

Florida Power & Light Company
Capacity Cost Recovery Clause
For the Period January through June 2017

Return on Capital Investments, Depreciation and Taxes
Incremental Nuclear NRC Compliance
(in Dollars)

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$40,417	$40,417	$40,417	$40,417	$40,417	$40,417	$242,500
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Clearings to Plant - Base		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other		$0	$0	$0	$0	$0	$0	$0
2.	Incremental Plant-In-Service/Depreciation	$74,167,553	$74,167,553	$74,167,553	$74,167,553	$74,167,553	$74,167,553	$74,167,553	
3.	Less: Accumulated Depreciation	$2,231,592	$2,387,196	$2,542,800	$2,698,403	$2,854,007	$3,009,611	$3,165,215	
4.	CWIP - Non Interest Bearing	$176,517	$216,934	$257,351	$297,767	$338,184	$378,601	$419,017	
5.	Net Investment (Lines 2 - 3 + 4)	$72,112,479	$71,997,292	$71,882,104	$71,766,917	$71,651,730	$71,536,543	$71,421,356	n/a
6.	Total Estimated Capital Expenditures Included in Base Rates (b)	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	
7.	Base Rate Capital Expenditures Closed to Plant-in-Service (c)	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	
8.	Remaining Amount Included in Base Rates (Lines 6 - 7)		$0	$0	$0	$0	$0	$0	
9.	Adjusted Net Investment (Lines 5 - 8)	$72,112,479	$71,997,292	$71,882,104	$71,766,917	$71,651,730	$71,536,543	$71,421,356	
10.	Average Net Investment		$72,054,885	$71,939,698	$71,824,511	$71,709,324	$71,594,136	$71,478,949	n/a
11.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (d)		$479,756	$478,989	$478,222	$477,455	$476,688	$475,921	$2,867,031
	b. Debt Component (Line 6 x debt rate x 1/12) (e)		$83,649	$83,515	$83,381	$83,247	$83,114	$82,980	$499,885
12.	Investment Expenses								
	a. Depreciation		$155,604	$155,604	$155,604	$155,604	$155,604	$155,604	$933,623
	b. Amortization		$0	$0	$0	$0	$0	$0	$0
	c. Other		$0	$0	$0	$0	$0	$0	$0
13.	Total System Recoverable Expenses (Lines 11 & 12)		$719,008	$718,108	$717,207	$716,306	$715,406	$714,505	$4,300,540

Notes:

[a] Represents nuclear NRC compliance plant-in-service in excess of the total estimated capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI) on line 6.

[b] Represents forecasted nuclear NRC compliance capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI).

[c] Represents base rate recoverable nuclear NRC compliance capital expenditures closed to plant-in-service.

[d] The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component is 4.9078%, which is based on the May 2016 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

[e] The Debt Component is 1.3931%, which is based on the May 2016 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

Totals may not add due to rounding.

Florida Power & Light Company
Capacity Cost Recovery Clause
For the Period July through December 2017

Return on Capital Investments, Depreciation and Taxes
Incremental Nuclear NRC Compliance
(in Dollars)

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$40,417	$40,417	$40,417	$40,417	$40,417	$40,417	$485,000
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Clearings to Plant - Base		$0	$0	$0	$0	$0	$0	$0
	d. Retirements		$0	$0	$0	$0	$0	$0	$0
	e. Other		$0	$0	$0	$0	$0	$0	$0
2.	Incremental Plant-In-Service/Depreciation Base (a)	$74,167,553	$74,167,553	$74,167,553	$74,167,553	$74,167,553	$74,167,553	$74,167,553	n/a
3.	Less: Accumulated Depreciation	$3,165,215	$3,320,819	$3,476,423	$3,632,027	$3,787,630	$3,943,234	$4,098,838	n/a
4.	CWIP - Non Interest Bearing	$419,017	$459,434	$499,851	$540,267	$580,684	$621,101	$661,517	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$71,421,356	$71,306,169	$71,190,981	$71,075,794	$70,960,607	$70,845,420	$70,730,233	n/a
6.	Total Estimated Capital Expenditures Included in Base Rates (b)	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	
7.	Base Rate Capital Expenditures Closed to Plant-in-Service (c)	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	
8.	Remaining Amount Included in Base Rates (Lines 6 - 7)	$0	$0	$0	$0	$0	$0	$0	
9.	Adjusted Net Investment (Lines 5 - 8)	$71,421,356	$71,306,169	$71,190,981	$71,075,794	$70,960,607	$70,845,420	$70,730,233	
10.	Average Net Investment		$71,363,762	$71,248,575	$71,133,388	$71,018,201	$70,903,013	$70,787,826	n/a
11.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (d)		$475,154	$474,387	$473,620	$472,853	$472,087	$471,320	$5,706,453
	b. Debt Component (Line 6 x debt rate x 1/12) (e)		$82,846	$82,712	$82,579	$82,445	$82,311	$82,178	$994,957
12.	Investment Expenses								
	a. Depreciation		$155,604	$155,604	$155,604	$155,604	$155,604	$155,604	$1,867,246
	b. Amortization		$0	$0	$0	$0	$0	$0	$0
	c. Other		$0	$0	$0	$0	$0	$0	$0
			$0	$0	$0	$0	$0	$0	$0
13.	Total System Recoverable Expenses (Lines 11 & 12)		$713,604	$712,704	$711,803	$710,902	$710,002	$709,101	$8,568,656

Notes:

(a) Represents nuclear NRC compliance plant-in-service in excess of the total estimated capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI) on line 6.

(b) Represents forecasted nuclear NRC compliance capital expenditures included in FPL's 2013 Test Year rate base (Docket No. 120015-EI).

(c) Represents base rate recoverable nuclear NRC compliance capital expenditures closed to plant-in-service.

(d) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%. The monthly Equity Component is 4.9078%, which is based on the May 2016 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(e) The Debt Component is 1.3931%, which is based on the May 2016 ROR Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU.

Totals may not add due to rounding.

Florida Power & Light Company
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2017 Projection

Contract	Capacity MW	Term Start	Term End	Contract Type
Indiantown	330	12/22/1995	12/1/2025	QF
Broward South - 1991 Agreement	3.5	1/1/1993	12/31/2026	QF

QF = Qualifying Facility

2017 Projection Capacity in Dollars

	January	February	March	April	May	June	July	August	September	October	November	December	Year-to-date
ICL	7,682,119	7,682,119	7,682,119	7,682,119	7,682,119	7,682,119	7,682,119	7,682,119	7,682,119	7,682,119	7,682,119	7,682,119	92,185,428
BS-NEG '91	110,600	110,600	110,600	110,600	110,600	110,600	110,600	110,600	110,600	110,600	110,600	110,600	1,327,200
Total	7,792,719	7,792,719	7,792,719	7,792,719	7,792,719	7,792,719	7,792,719	7,792,719	7,792,719	7,792,719	7,792,719	7,792,719	93,512,628

Florida Power & Light Company
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2017 Projection

Contract	Counterparty	Identification	Contract Start Date	Contract End Date
1	JEA - SJRPP	Other Entity	April 2, 1982	September 30, 2021
2	Solid Waste Authority (40MW)	Other Entity	January 1, 2012	April 1, 1932
3	Solid Waste Authority (70MW)	Other Entity	July 16, 2016	May 31, 2034

2017 Capacity in MW

Contract	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
1	375	375	375	375	375	375	375	375	375	375	375	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
Total	485	485	485	485	485	485	485	485	485	485	485	485

2017 Capacity in Dollars

Contract	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
1	[redacted]											
2												
3												
Total	6,415,166	6,415,166	6,415,166	6,415,166	6,415,166	6,455,566	6,455,566	6,455,566	6,455,566	5,509,951	5,509,951	5,509,951

Total Capacity Payments to Non-Cogenerators for 2017 [1]	$71,433,553

[1] Appendix II, page 2, line 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

CEDAR BAY TRANSACTION

Regulatory Asset Related to the Loss of the PPA and Income Tax Gross-Up (Amortization and Return Calculation)

For the Period January through December 2016

Line No.	Description	Beginning of Period	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Estimated Total
1	Regulatory Asset - Loss of PPA		$ 419,946,428	$ 416,058,035	$ 412,169,642	$ 408,281,249	$ 404,392,856	$ 400,504,463	$ 396,616,124	$ 392,727,731	$ 388,839,338	$ 384,950,945	$ 381,062,552	$ 377,174,159	n/a
2	Regulatory Asset - Loss of PPA Amort		3,888,393	3,888,393	3,888,393	3,888,393	3,888,393	3,888,339	3,888,393	3,888,393	3,888,393	3,888,393	3,888,393	3,888,393	$ 46,660,662
3	Unamortized Regulatory Asset - Loss of PPA	$ 419,946,428	$ 416,058,035	$ 412,169,642	$ 408,281,249	$ 404,392,856	$ 400,504,463	$ 396,616,124	$ 392,727,731	$ 388,839,338	$ 384,950,945	$ 381,062,552	$ 377,174,159	$ 373,285,766	n/a
4	Average Unamortized Regulatory Asset - Loss of PPA		$ 418,002,232	$ 414,113,839	$ 410,225,446	$ 406,337,053	$ 402,448,660	$ 398,560,293	$ 394,671,927	$ 390,783,534	$ 386,895,141	$ 383,006,748	$ 379,118,355	$ 375,229,962	n/a
5	Regulatory Asset - Income Tax Gross Up		$ 263,727,041	$ 261,285,124	$ 258,843,207	$ 256,401,290	$ 253,959,373	$ 251,517,416	$ 249,075,499	$ 246,633,582	$ 244,191,665	$ 241,749,748	$ 239,307,831	$ 236,865,914	
6	Regulatory Asset Amortization - Income Tax Gross-Up		2,441,917.00	2,441,917.00	2,441,917.00	2,441,917.00	2,441,917.00	2,441,957.16	2,441,917.00	2,441,917.00	2,441,917.00	2,441,917.00	2,441,917.00	2,441,917.00	29,303,044
7	Unamortized Regulatory Asset - Income Tax Gross Up		261,285,124	258,843,207	256,401,290	253,959,373	251,517,456	249,075,459	246,633,582	244,191,665	241,749,748	239,307,831	236,865,914	234,423,997	
8	Return on Unamortized Regulatory Asset - Loss of PPA only														
	a. Equity Component [a]		1,679,031	1,663,412	1,647,794	1,632,175	1,616,556	1,600,937	1,614,129	1,598,226	$ 1,582,324	$ 1,566,421	$ 1,550,518	$ 1,534,615	19,286,139
	b. Equity Comp. grossed up for taxes (Line 8a / 0.61425) [b]		2,733,466	2,708,038	2,682,611	2,657,183	2,631,755	2,606,328	2,627,805	2,601,915	2,576,026	2,550,136	2,524,246	2,498,357	31,397,866
	c. Debt Component (Line 4 * debt rate / 12)		519,159	514,329	509,500	504,671	499,841	495,012	458,175	453,661	449,147	444,633	440,118	435,604	5,723,849
9	Total Return Requirements (Line 8b + 8c)		$ 3,252,625	$ 3,222,368	$ 3,192,111	$ 3,161,854	$ 3,131,597	$ 3,101,340	$ 3,085,980	$ 3,055,576	$ 3,025,172	$ 2,994,768	$ 2,964,365	$ 2,933,961	$ 37,121,715
10	Total Recoverable Expenses (Line 2 + 6 + 9)		9,582,935	9,552,678	9,522,421	9,492,164	9,461,907	9,431,637	9,416,290	9,385,886	9,355,482	9,325,078	9,294,675	9,264,271	$ 113,085,422

[a] The monthly Equity Component for the Jan. - Jun. 2016 actual period is 4.8201%, reflects a 10.5% return on equity. Monthly Equity Component for the Jul. - Dec. 2016 estimated period is 4.9078% based on the May 2016 ROR Earnings Surveillance Report, reflects a 10.5% return on equity, consistent with FPSC Order No. PSC-12-0425-PAA-EU.
[b] Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35%.
[c] The Debt Component for the Jan. - Jun. 2016 actual period is 1.4904%. Debt Component for the Jul. - Dec. 2016 estimated period is 1.3931% based on the May 2016 ROR Earnings Surveillance Report, reflects a 10.5% ROE, consistent with FPSC Order No. PSC-12-0425-PAA-EU.
(d) Recovery of the Cedar Bay Transaction is based on the settlement agreement approved by the FPSC in Docket No. 150075-EI at the special agenda on August 27th, 2015.

TOTAL MAY NOT ADD DUE TO ROUNDING

FLORIDA POWER & LIGHT COMPANY

CEDAR BAY TRANSACTION

Regulatory Asset Related to the Loss of the PPA and Income Tax Gross-Up (Amortization and Return Calculation)

For the Period January through December 2017

Line No.	Description	Beginning of Period	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	Projected Total
1	Regulatory Asset - Loss of PPA - Previously in Clause	$373,285,766	$373,285,766	$369,397,373	$365,508,980	$361,620,587	$357,732,194	$353,843,801	$349,955,408	$346,067,016	$342,178,623	$338,290,230	$334,401,837	$330,513,444	n/a
2	Regulatory Asset - Loss of PPA - Transferred From Base to Clause	$72,857,143	$72,857,143	$72,098,214	$71,339,286	$70,580,357	$69,821,429	$69,062,500	$68,303,571	$67,544,643	$66,785,714	$66,026,786	$65,267,857	$64,508,929	
3	Regulatory Asset - Loss of PPA Amort		$4,647,321	$4,647,321	$4,647,321	$4,647,321	$4,647,321	$4,647,321	$4,647,321	$4,647,321	$4,647,321	$4,647,321	$4,647,321	$4,647,321	$55,767,857
4	Unamortized Regulatory Asset - Loss of PPA	$446,142,908	$441,495,587	$436,848,266	$432,200,944	$427,553,623	$422,906,301	$418,258,980	$413,611,658	$408,964,337	$404,317,016	$399,669,694	$395,022,373	$390,375,051	n/a
5	Average Unamortized Regulatory Asset - Loss of PPA		$443,819,248	$439,171,926	$434,524,605	$429,877,283	$425,229,962	$420,582,641	$415,935,319	$411,287,998	$406,640,676	$401,993,355	$397,346,033	$392,698,712	n/a
6	Regulatory Asset - Income Tax Gross Up - Previously in Clause	$234,423,997	$234,423,997	$231,982,080	$229,540,163	$227,098,246	$224,656,329	$222,214,412	$219,772,495	$217,330,578	$214,888,661	$212,446,744	$210,004,827	$207,562,910	
7	Regulatory Asset - Income Tax Gross Up - Transferred From Base to Clause	$45,754,410	$45,754,410	$45,277,802	$44,801,193	$44,324,585	$43,847,976	$43,371,368	$42,894,760	$42,418,151	$41,941,543	$41,464,935	$40,988,326	$40,511,718	
8	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	$35,022,305
9	Unamortized Regulatory Asset - Income Tax Gross Up	$280,178,407	$277,259,881	$274,341,356	$271,422,831	$268,504,305	$265,585,780	$262,667,255	$259,748,729	$256,830,204	$253,911,678	$250,993,153	$248,074,628	$245,156,102	
10	Return on Unamortized Regulatory Asset - Loss of PPA only														
	a. Equity Component [a]		$1,815,132	$1,796,125	$1,777,119	$1,758,112	$1,739,105	$1,720,099	$1,701,092	$1,682,086	$1,663,079	$1,644,072	$1,625,066	$1,606,059	$20,527,147
	b. Equity Comp. grossed up for taxes (Line 10a / 0.61425) [b]		$2,955,038	$2,924,095	$2,893,152	$2,862,209	$2,831,267	$2,800,324	$2,769,381	$2,738,438	$2,707,495	$2,676,553	$2,645,610	$2,614,667	$33,418,229
	c. Debt Component (Line 5 * debt rate / 12)		$515,230	$509,835	$504,440	$499,045	$493,649	$488,254	$482,859	$477,464	$472,069	$466,674	$461,279	$455,884	$5,826,682
11	Total Return Requirements (Line 10b + 10c)		$3,470,268	$3,433,930	$3,397,592	$3,361,254	$3,324,916	$3,288,578	$3,252,240	$3,215,902	$3,179,565	$3,143,227	$3,106,889	$3,070,551	$39,244,911
12	Total Recoverable Expenses (Line 3 + 8 + 11)		$11,036,114	$10,999,776	$10,963,439	$10,927,101	$10,890,763	$10,854,425	$10,818,087	$10,781,749	$10,745,411	$10,709,073	$10,672,736	$10,636,398	$130,035,072

(a) The monthly Equity Component for the Jan. - Dec. 2017 estimated period is 4.9078% based on the May 2016 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.
(b) Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35%.
(c) The Debt Component for the Jan. - Dec. 2017 estimated period is 1.3931% based on the May 2016 ROR Surveillance Report and reflects a 10.5% ROE, per FPSC Order No. PSC-12-0425-PAA-EU.
(d) Recovery of the Cedar Bay Transaction is based on the settlement agreement approved by the FPSC in Docket No. 150075-EI at the special agenda on August 27th, 2015.

TOTAL MAY NOT ADD DUE TO ROUNDING

FLORIDA POWER & LIGHT COMPANY

CEDAR BAY TRANSACTION

Regulatory Liability - Book/Tax Timing Difference Associated to Plant Asset - Amortization and Return Calculation

For the Period January through December 2016

Line No.	Description	Beginning of Period	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Estimated Total
1	Regulatory Liability - Book/Tax Timing Difference		(6,823,733)	(6,760,550)	(6,697,367)	(6,634,184)	(6,571,001)	(6,507,818)	(6,444,635)	(6,381,452)	(6,318,269)	(6,255,086)	(6,191,903)	(6,128,720)	n/a
2	Regulatory Liability Amortization		63,183	63,183	63,183	63,183	63,183	63,183	63,183	63,183	63,183	63,183	63,183	63,183	$ 758,196
3	Unamortized Regulatory Liability - Book/Tax Timing Diff	$ (6,823,733)	$ (6,760,550)	$ (6,697,367)	$ (6,634,184)	$ (6,571,001)	$ (6,507,818)	$ (6,444,635)	$ (6,381,452)	$ (6,318,269)	$ (6,255,086)	$ (6,191,903)	$ (6,128,720)	$ (6,065,537)	n/a
4	Average Unamortized Regulatory Liability - Book/Tax Timing Difference		(6,792,142)	(6,728,959)	(6,665,776)	(6,602,593)	(6,539,410)	(6,476,227)	(6,413,044)	(6,349,861)	(6,286,678)	(6,223,495)	(6,160,312)	(6,097,129)	n/a
5	Return on Unamortized Regulatory Liability - Book/Tax Timing Difference														
	a. Equity Component [a]		(27,283)	(27,029)	(26,775)	(26,521)	(26,268)	(26,014)	(26,228)	(25,970)	(25,711)	(25,453)	(25,194)	(24,936)	(313,381)
	b. Equity Comp. grossed up for taxes (Line 5a / 0.61425) [b]		(44,416)	(44,003)	(43,590)	(43,177)	(42,764)	(42,350)	(42,699)	(42,279)	(41,858)	(41,437)	(41,017)	(40,596)	(510,186)
	c. Debt Component (Line 4 * debt rate / 12)		(8,436)	(8,357)	(8,279)	(8,200)	(8,122)	(8,043)	(7,445)	(7,372)	(7,298)	(7,225)	(7,152)	(7,078)	(93,007)
6	Total Return Requirements (Line 5b + 5c)		$ (52,852)	$ (52,360)	$ (51,869)	$ (51,377)	$ (50,885)	$ (50,394)	$ (50,144)	$ (49,650)	$ (49,156)	$ (48,662)	$ (48,168)	$ (47,674)	$ (603,193)
7	Total Recoverable Expenses (Line 2 + 6)		$ (116,035.08)	$ (115,543.43)	$ (115,051.78)	$ (114,560.13)	$ (114,068.48)	$ (113,576.83)	$ (113,327.24)	$ (112,833.20)	$ (112,339.17)	$ (111,845.13)	$ (111,351.10)	$ (110,857.06)	$ (1,361,389)

[a] The monthly Equity Component for the Jan. - Jun. 2016 actual period is 4.8201%, reflects a 10.5% return on equity. Monthly Equity Component for the Jul. - Dec. 2016 estimated period is 4.9078% based on the May 2016 ROR Earnings Surveillance Report, reflects a 10.5% return on equity, consistent with FPSC Order No. PSC-12-0425-PAA-EU.

[b] Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35%.

[c] The Debt Component for the Jan. - Jun. 2016 actual period is 1.4904%. Debt Component for the Jul. - Dec. 2016 estimated period is 1.3931% based on the May 2016 ROR Earnings Surveillance Report, reflects a 10.5% ROE, consistent with FPSC Order No. PSC-12-0425-PAA-EU.

(d) Recovery of the Cedar Bay Transaction is based on the settlement agreement approved by the FPSC in Docket No. 150075-EI at the special agenda on August 27th, 2015.

TOTAL MAY NOT FOOT DUE TO ROUNDING

FLORIDA POWER & LIGHT COMPANY

CEDAR BAY TRANSACTION

Regulatory Liability - Book/Tax Timing Difference Associated to Plant Asset - Amortization and Return Calculation

For the Period January through December 2017

Line No.	Description	Beginning of Period	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	Projected Total
1	Regulatory Liability - Book/Tax Timing Difference		($6,065,537)	($6,002,354)	($5,939,171)	($5,875,988)	($5,812,805)	($5,749,622)	($5,686,439)	($5,623,256)	($5,560,073)	($5,496,890)	($5,433,707)	($5,370,524)	n/a
2	Regulatory Liability Amortization		$63,183	$63,183	$63,183	$63,183	$63,183	$63,183	$63,183	$63,183	$63,183	$63,183	$63,183	$63,183	$758,196
3	Unamortized Regulatory Liability - Book/Tax Timing Diff	($6,065,537)	($6,002,354)	($5,939,171)	($5,875,988)	($5,812,805)	($5,749,622)	($5,686,439)	($5,623,256)	($5,560,073)	($5,496,890)	($5,433,707)	($5,370,524)	($5,307,341)	n/a
4	Average Unamortized Regulatory Liability - Book/Tax Timing Difference		($6,033,946)	($5,970,763)	($5,907,580)	($5,844,397)	($5,781,214)	($5,718,031)	($5,654,848)	($5,591,665)	($5,528,482)	($5,465,299)	($5,402,116)	($5,338,933)	n/a
5	Return on Unamortized Regulatory Liability - Book/Tax Timing Difference														
	a. Equity Component [a]		($24,678)	($24,419)	($24,161)	($23,902)	($23,644)	($23,386)	($23,127)	($22,869)	($22,610)	($22,352)	($22,094)	($21,835)	($279,077)
	b. Equity Comp. grossed up for taxes (Line 5a / 0.61425) [b]		($40,175)	($39,755)	($39,334)	($38,913)	($38,492)	($38,072)	($37,651)	($37,230)	($36,810)	($36,389)	($35,968)	($35,548)	($454,337)
	c. Debt Component (Line 4 * debt rate / 12)		($7,005)	($6,931)	($6,858)	($6,785)	($6,711)	($6,638)	($6,565)	($6,491)	($6,418)	($6,345)	($6,271)	($6,198)	($79,217)
6	Total Return Requirements (Line 5b + 5c)		($47,180)	($46,686)	($46,192)	($45,698)	($45,204)	($44,710)	($44,216)	($43,722)	($43,228)	($42,734)	($42,240)	($41,746)	($533,554)
7	Total Recoverable Expenses (Line 2 + 6)		($110,363)	($109,869)	($109,375)	($108,881)	($108,387)	($107,893)	($107,399)	($106,905)	($106,411)	($105,917)	($105,423)	($104,929)	($1,291,750)

(a) The monthly Equity Component for the Jan. - Dec. 2017 estimated period is 4.9078% based on the May 2016 ROR Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.
(b) Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35%.
(c) The Debt Component for the Jan. - Dec. 2017 estimated period is 1.3931% based on the May 2016 ROR Surveillance Report and reflects a 10.5% ROE, per FPSC Order No. PSC-12-0425-PAA-EU.
(d) Recovery of the Cedar Bay Transaction is based on the settlement agreement approved by the FPSC in Docket No. 150075-EI at the special agenda on August 27th, 2015.

TOTAL MAY NOT FOOT DUE TO ROUNDING

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.50%

CAPITAL STRUCTURE AND COST RATES PER MAY 2016 EARNINGS SURVEILLANCE REPORT

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	8,001,609,073	28.728%	4.64%	1.33%	1.33%
SHORT_TERM_DEBT	439,350,198	1.577%	1.86%	0.03%	0.03%
PREFERRED_STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER_DEPOSITS	418,988,300	1.504%	2.07%	0.03%	0.03%
COMMON_EQUITY	13,017,322,068	46.735%	10.50%	4.91%	7.99%
DEFERRED_INCOME_TAX	5,973,525,955	21.446%	0.00%	0.00%	0.00%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	2,534,605	0.009%	8.27%	0.00%	0.00%
TOTAL	$27,853,330,199	100.00%		6.30%	9.38%

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	$8,001,609,073	38.07%	4.638%	1.766%	1.766%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	13,017,322,068	61.93%	10.500%	6.503%	10.587%
TOTAL	$21,018,931,141	100.00%		8.269%	12.352%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	1.3325%
SHORT TERM DEBT	0.0293%
CUSTOMER DEPOSITS	0.0312%
TAX CREDITS -WEIGHTED	0.0002%
TOTAL DEBT	**1.3931%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.9072%
TAX CREDITS -WEIGHTED	0.0006%
TOTAL EQUITY	**4.9078%**
TOTAL	6.3009%
PRE-TAX EQUITY	7.9899%
PRE-TAX TOTAL	9.3830%

Note:

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

FLORIDA POWER & LIGHT COMPANY
BASED ON RATE CASE ALLOCATION OF GAS TURBINE PRODUCTION REVENUE REQUIREMENT
JANUARY 2017 THROUGH DECEMBER 2017
12CP & 25% COS Allocation Method

	Rate	Demand & Energy Component[1] $000s	Allocation	2017 WC3 Revenue Requirement Allocation @ 10.5% ROE
	(a)	(b)	(c)	(d)
1	CILC-1D	38,614	2.0%	$2,869,680
2	CILC-1G	1,498	0.1%	$111,306
3	CILC-1T	20,518	1.1%	$1,524,803
4	GS1	106,217	5.6%	$7,893,728
5	GSCU-1	968	0.1%	$71,947
6	GSD1	424,000	22.4%	$31,510,303
7	GSLD1	171,270	9.0%	$12,728,257
8	GSLD2	36,109	1.9%	$2,683,482
9	GSLD3	2,439	0.1%	$181,258
10	MET	1,474	0.1%	$109,566
11	OL-1	638	0.0%	$47,385
12	OS-2	147	0.0%	$10,945
13	RS1	1,085,234	57.3%	$80,651,145
14	SL-1	3,664	0.2%	$272,266
15	SL-2	451	0.0%	$33,546
16	SST-DST	180	0.0%	$13,406
17	SST-TST	1,110	0.1%	$82,458
18				
19	Total	1,894,531	100.0%	$140,795,481

Notes:
[1] Docket 160021-EI 2017 Test Year MFR E-6b attachment 2 of 2 lines 5 + 17 Other Production revenue requirements (12CP & 25% Method)

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY RECOVERY FACTOR FOR WEST COUNTY 3
JANUARY 2017 THROUGH DECEMBER 2017
12CP & 25% 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	57,063,506,058	-	-	$80,651,145		0.00141
2	GS1/GST1/WIES1	5,971,311,587	-	-	$7,893,728		0.00132
3	GSD1/GSDT1/HLFT1	25,836,330,536	50.15375%	70,567,469	$31,510,303	0.45	
4	OS2	10,793,313	-	-	$10,945		0.00101
5	GSLD1/GSLDT1/CS1/CST1/HLFT2	10,511,832,443	56.71170%	25,391,181	$12,728,257	0.50	
6	GSLD2/GSLDT2/CS2/CST2/HLFT3	2,516,449,511	65.79207%	5,239,524	$2,683,482	0.51	
7	GSLD3/GSLDT3/CS3/CST3	172,996,790	68.69783%	344,963	$181,258	0.53	
8	SST1T	89,667,754	11.31969%	1,085,123	$82,458		
9	SST1D1/SST1D2/SST1D3	11,856,926	29.68376%	54,718	$13,406		
10	CILC D/CILC G	2,789,895,442	74.14313%	5,154,590	$2,980,986	0.58	
11	CILC T	1,508,389,554	76.33683%	2,706,802	$1,524,803	0.56	
12	MET	91,208,296	64.64301%	193,281	$109,566	0.57	
13	OL1/SL1/PL1	658,751,104	-	-	$319,651		0.00049
14	SL2, GSCU1	103,004,444	-	-	$105,494		0.00102
		107,335,993,758		110,737,652	$140,795,481		

(1) Projected kwh sales for the period January 2017 through December 2017
(2) Billing kW Load Factor based on 2012-2014 load research data and 2016 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 FACTOR RDC ** ($/kw)	SDD ** ($/kw)
ISST1D	$0.06	$0.03
ISST1T	$0.06	$0.03
SST1T	$0.06	$0.03
SST1D1/SST1D2/SST1I	$0.06	$0.03

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF REVENUE IMPACT FOR WEST COUNTY 3
12CP & 25% COS Allocation Method

	(a)	Total Revenue[1] (b)	Total WC3 Costs (c)		% Increase (d)
1	RS1/RTR1	$5,452,009,987	$80,651,145		1.48%
2	GS1/GST1	$572,669,917	$7,893,728		1.38%
3	GSD1/GSDT1/HLFT1 (21-499 kW)	$2,007,139,401	$31,510,303		1.57%
4	OS2	$1,401,750	$10,945		0.78%
5	GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	$726,636,417	$12,728,257		1.75%
6	GSLD2/GSLDT2/CS2/CST2/HLFT3(2,000+ kW)	$160,635,608	$2,683,482		1.67%
7	GSLD3/GSLDT3/CS3/CST3	$10,332,049	$181,258		1.75%
8	ISST1D	$0	$0		0.00%
9	ISST1T	$0	$0		0.00%
10	SST1T	$7,290,651	$82,458		1.13%
11	SST1D1/SST1D2/SST1D3	$1,209,478	$13,406		1.11%
12	CILC D/CILC G	$157,825,087	$2,980,986		1.89%
13	CILC T	$72,613,947	$1,524,803		2.10%
14	MET	$7,187,414	$109,566		1.52%
15	OL1/SL1/PL1	$132,533,946	$319,651		0.24%
16	SL2, GSCU1	$9,174,223	$105,494		1.15%
17					
18	TOTAL	$9,318,659,875	$140,795,481		1.51%
				1.5x	2.27%
				Max	2.10%

Notes
1) Based on Projections of 2017 base and clause revenues.

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR
INCLUDING WEST COUNTY ENERGY CENTER UNIT 3

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
RATE SCHEDULE	Jan 2017 - Dec 2017 Capacity Recovery Factor				2017 WCEC-3 Capacity Recovery Factor				Total Jan 2017 - Dec 2017 Capacity Recovery Factor			
	($KW)	($/kwh)	RDC ($/KW) [1]	SDD ($/KW) [2]	($KW)	($/kwh)	RDC ($/KW)	SDD ($/KW)	($KW)	($/kwh)	RDC ($/KW) [1]	SDD ($/KW) [2]
RS1/RTR1	-	0.00298	-	-	-	0.00141	-	-	-	0.00439	-	-
GS1/GST1	-	0.00278	-	-	-	0.00132	-	-	-	0.00410	-	-
GSD1/GSDT1/HLFT1	0.94	-	-	-	0.45	-	-	-	1.39	-	-	-
OS2	-	0.00214	-	-	-	0.00101	-	-	-	0.00315	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	1.05	-	-	-	0.50	-	-	-	1.55	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	1.07	-	-	-	0.51	-	-	-	1.58	-	-	-
GSLD3/GSLDT3/CS3/CST3	1.09	-	-	-	0.53	-	-	-	1.62	-	-	-
SST1T	-	-	$0.13	$0.06	-	-	$0.06	$0.03	-	-	$0.19	$0.09
SST1D1/SST1D2/SST1D3	-	-	$0.13	$0.06	-	-	$0.06	$0.03	-	-	$0.19	$0.09
CILC D/CILC G	1.20	-	-	-	0.58	-	-	-	1.78	-	-	-
CILC T	1.17	-	-	-	0.56	-	-	-	1.73	-	-	-
MET	1.19	-	-	-	0.57	-	-	-	1.76	-	-	-
OL1/SL1/PL1	-	0.00092	-	-	-	0.00049	-	-	-	0.00141	-	-
SL2, GSCU1	-	0.00212	-	-	-	0.00102	-	-	-	0.00314	-	-

[1] RDC=((Total Capacity Costs)/(Projected Avg 12CP @gen)(.10)(demand loss expansion factor))/12 months

[2] SDD=((Total Capacity Costs)/(Projected Avg 12 CP @gen)/(21 onpeak days)(demand loss expansion factor))/12 months

Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

APPENDIX IV
CAPACITY COST RECOVERY
CURRENT COST ALLOCATION METHODOLOGY
12CP AND 1/13TH

JANUARY 2017 THROUGH DECEMBER 2017

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 24
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT & SUPPLEMENTAL)*Notice of Adoption of Terry J. Keith's testimony and exhibits by Renae B. Deaton, filed on October 3, 2016, (FPSC DN #07930-16).
DESCRIPTION: *R. B. Deaton TJK-7

TJK-7
DOCKET NO. 160001-EI
FPL WITNESS: TERRY J.KEITH
EXHIBIT _____
PAGES 1-7
SEPTEMBER 2, 2016

APPENDIX IV
CAPACITY COST RECOVERY
2017 FACTORS JAN 2017 THROUGH DEC 2017
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4	Rate Case Allocation of Gas Turbine Production Revenue Requirement January 2017 through December 2017	T. J. Keith
5	Calculation of Revenue Impact for West County Energy Center Unit 3	T. J. Keith
6	Calculation of Capacity Cost Recovery Factor for West County Energy Center Unit 3	T. J. Keith
7	Calculation of Capacity Recovery Factor including West County Energy Center Unit 3 for January 2017 through December 2017	T. J. Keith

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
PROJECTED CAPACITY PAYMENTS
ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

Line No.	(1)	(2) January Estimated	(3) February Estimated	(4) March Estimated	(5) April Estimated	(6) May Estimated	(7) June Estimated	(8) July Estimated	(9) August Estimated	(10) September Estimated	(11) October Estimated	(12) November Estimated	(13) December Estimated	(14) Total
1	Capacity Payments To Non-Cogenerators	$6,165,633	$6,165,633	$6,165,633	$6,165,633	$6,165,633	$6,206,033	$6,206,033	$6,206,033	$6,206,033	$5,260,418	$5,260,418	$5,260,418	$71,433,553
2	Capacity Payments To Cogenerators	$7,792,719	$7,792,719	$7,792,719	$7,792,719	$7,792,719	$7,792,719	$7,792,719	$7,792,719	$7,792,719	$7,792,719	$7,792,719	$7,792,719	$93,512,628
3	Cedar Bay Transaction - Regulatory Asset - Amortization and Return	$11,036,114	$10,999,776	$10,963,439	$10,927,101	$10,890,763	$10,854,425	$10,818,087	$10,781,749	$10,745,411	$10,709,073	$10,672,736	$10,636,398	$130,035,072
4	Cedar Bay Transaction - Regulatory Liability - Amortization and Return	($110,363)	($109,869)	($109,375)	($108,881)	($108,387)	($107,893)	($107,399)	($106,905)	($106,411)	($105,917)	($105,423)	($104,929)	($1,291,750)
5	SJRPP Suspension Accrual	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($756,990)	($9,083,880)
6	Return Requirements On SJRPP Suspension Liability	($145,512)	($139,593)	($133,674)	($127,756)	($121,837)	($115,918)	($109,999)	($104,080)	($98,161)	($92,242)	($86,323)	($80,404)	($1,355,497)
7	Incremental Plant Security Costs O&M	$3,473,475	$2,913,424	$3,413,885	$3,611,563	$2,954,626	$3,176,849	$3,394,487	$2,904,413	$3,079,020	$3,418,743	$3,226,839	$3,638,259	$39,205,584
8	Incremental Plant Security Costs Capital	$213,189	$215,760	$220,450	$227,413	$235,054	$242,816	$250,422	$258,523	$266,548	$273,929	$281,068	$308,800	2,993,970
9	Incremental Nuclear NRC Compliance Costs O&M	$109,401	$109,401	$181,901	$109,401	$109,401	$171,901	$109,401	$109,401	$171,901	$109,401	$59,401	$121,901	$1,472,810
10	Incremental Nuclear NRC Compliance Costs Capital	$719,008	$718,108	$717,207	$716,306	$715,406	$714,505	$713,604	$712,704	$711,803	$710,902	$710,002	$709,101	$8,568,656
11	Transmission Revenues From Capacity Sales	($1,392,948)	($1,120,324)	($683,816)	($481,000)	($269,125)	($185,125)	($210,125)	($210,125)	($253,125)	($196,250)	($283,500)	($497,000)	($5,782,463)
12	System Total	$27,103,727	$26,788,045	$27,771,378	$28,075,510	$27,607,263	$27,993,323	$28,100,242	$27,587,442	$27,758,749	$27,123,787	$26,770,946	$27,028,272	$329,708,684
13	Jurisdictional % *													95.04658%
14	Jurisdictionalized Capacity Payments													$313,376,833
15	2015 FINAL TRUE-UP -- (Over)/Under Recovery													($5,938,824)
16	2016 ACT/EST TRUE-UP -- (Over)/Under Recovery													($9,639,909)
17	Nuclear Cost Recovery Clause													$0
18	Cape Canaveral GBRA True-up													($1,890,528)
19	Total (Lines 14+15+16+17+18)													$295,907,572
20	Revenue Tax Multiplier													1.00072
21	Total Recoverable Capacity Payments													$296,120,626
22														
23	*Calculation of Jurisdictional %													
24	.....AVG. 12CP													
25	.....AT GEN (MW).....%													
26	FPSC.....19,893.365.....95.04658%													
27	FERC.....1,036.757.....4.95342%													
28	TOTAL.....20,930.121.....100.00000%													
29														
30	* Based on 2017 Estimated Data													
31	Totals may not add up due to rounding.													
32														
33														
34														
35														
36														
37														
38														
39														

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY DEMAND ALLOCATION % BY RATE CLASS
ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
RATE SCHEDULE	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) [g]	Percentage of Sales at Generation (%) [h]	Percentage of Demand at Generation (%) [i]
RS1/RTR1	59.146%	57,063,506,058	11,013,646	1.06430156	1.04862829	59,838,406,779	11,721,841	53.21566%	58.92337%
GS1/GST1	65.027%	5,971,311,587	1,048,260	1.06430156	1.04862829	6,261,686,259	1,115,665	5.56866%	5.60823%
GSD1/GSDT1/HLFT1	72.765%	25,836,330,536	4,053,251	1.06421646	1.04856471	27,091,064,436	4,313,536	24.09270%	21.68329%
OS2	92.223%	10,793,313	1,336	1.05687787	1.02669200	11,081,408	1,412	0.00985%	0.00710%
GSLD1/GSLDT1/CS1/CST1/HLFT2	73.257%	10,511,832,443	1,638,034	1.06313919	1.04778551	11,014,145,717	1,741,458	9.79513%	8.75396%
GSLD2/GSLDT2/CS2/CST2/HLFT3	87.653%	2,516,449,511	327,730	1.05469612	1.04113164	2,619,955,206	345,656	2.32999%	1.73754%
GSLD3/GSLDT3/CS3/CST3	86.088%	172,996,790	22,940	1.02180107	1.01700518	175,938,632	23,440	0.15647%	0.11783%
SST1T	107.395%	89,667,754	9,531	1.02180107	1.01700518	91,192,570	9,739	0.08110%	0.04895%
SST1D1/SST1D2/SST1D3	78.275%	11,856,926	1,729	1.03476555	1.02669200	12,173,411	1,789	0.01083%	0.00899%
CILC D/CILC G	87.305%	2,789,895,442	364,790	1.05313565	1.04053446	2,902,982,347	384,173	2.58169%	1.93116%
CILC T	91.242%	1,508,389,554	188,718	1.02180107	1.01700518	1,534,039,990	192,832	1.36426%	0.96933%
MET	71.670%	91,208,296	14,528	1.03476555	1.02669200	93,642,828	15,033	0.08328%	0.07557%
OL1/SL1/PL1	586.798%	658,751,104	12,815	1.06430156	1.04862829	690,785,044	13,639	0.61433%	0.06856%
SL2, GSCU1	95.157%	103,004,444	12,357	1.06430156	1.04862829	108,013,374	13,152	0.09606%	0.06611%
TOTAL		107,335,993,758	18,709,665			112,445,108,001	19,893,365	100.00000%	100.00000%

[a] AVG 12 CP load factor based on 2013-2015 load research data and 2017 projections.

[b] Projected kwh sales for the period January 2017 through December 2017.

[c] Calculated: Col(3)/(8760 hours * Col(2))

[d] Based on 2016 demand losses.

[e] Based on 2016 energy losses.

[f] Col(3) * Col(6)

[g] Col(4) * Col(5)

[h] Col(7) / Total for Col(7)

[i] Col(8) / Total for Col(8)

Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR
12CP AND 1/13th COS ALLOCATION
ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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]
RS1/RTR1	53.21566%	58.92337%	$12,121,734	$161,062,382	$173,184,116	57,063,506,058	-	-	-	0.00303	-	-
GS1/GST1	5.56866%	5.60823%	$1,268,458	$15,329,642	$16,598,100	5,971,311,587	-	-	-	0.00278	-	-
GSD1/GSDT1/HLFT1	24.09270%	21.68329%	$5,487,958	$59,269,570	$64,757,528	25,836,330,536	50.15375%	70,567,469	0.92	-	-	-
OS2	0.00985%	0.00710%	$2,245	$19,401	$21,646	10,793,313	-	-	-	0.00201	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	9.79513%	8.75396%	$2,231,185	$23,928,272	$26,159,457	10,511,832,443	56.71170%	25,391,181	1.03	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	2.32999%	1.73754%	$530,736	$4,749,434	$5,280,170	2,516,449,511	65.79207%	5,239,524	1.01	-	-	-
GSLD3/GSLDT3/CS3/CST3	0.15647%	0.11783%	$35,641	$322,076	$357,716	172,996,790	68.69783%	344,963	1.04	-	-	-
SST1T	0.08110%	0.04895%	$18,473	$133,814	$152,288	89,667,754	11.31969%	1,085,123	-	-	$0.13	$0.06
SST1D1/SST1D2/SST1D3	0.01083%	0.00899%	$2,466	$24,583	$27,049	11,856,926	29.68376%	54,718	-	-	$0.13	$0.06
CILC D/CILC G	2.58169%	1.93116%	$588,070	$5,278,683	$5,866,753	2,789,895,442	74.14313%	5,154,590	1.14	-	-	-
CILC T	1.36426%	0.96933%	$310,757	$2,649,586	$2,960,343	1,508,389,554	76.33683%	2,706,802	1.09	-	-	-
MET	0.08328%	0.07557%	$18,970	$206,560	$225,530	91,208,296	64.64301%	193,281	1.17	-	-	-
OL1/SL1/PL1	0.61433%	0.06856%	$139,935	$187,405	$327,341	658,751,104	-	-	-	0.00050	-	-
SL2, GSCU1	0.09606%	0.06611%	$21,881	$180,707	$202,588	103,004,444	-	-	-	0.00197	-	-
TOTAL			$22,778,510	$273,342,116	$296,120,626	107,335,993,758		110,737,652				

[a] Obtained from Page 2, Col(9)

[b] Obtained from Page 2, Col(10)

[c] (Total Capacity Costs/13) * Col(2)

[d] (Total Capacity Costs/13 * 12) * Col(3)

[e] Col(4) + Col(5)

[f] Projected kwh sales for the period January 2017 through December 2017.

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

[h] Col(7) / (Col(8) *730)

[i] Col(6) / Col(9)

[j] Col(6) / Col(7)

[k] RDC = Reservation Demand Charge - (Total Col 6)/(Page 2 Total Col 8)(.10)(Page 2 Col 5)/12 Months

[l] SDD = Sum of Daily Demand Charge - (Total Col 6)/(Page 2 Total Col 8)/(21 onpeak days)(Page 2 Col 5)/12 Months

Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
BASED ON RATE CASE ALLOCATION OF GAS TURBINE PRODUCTION REVENUE REQUIREMENT
JANUARY 2017 THROUGH DECEMBER 2017
12CP & 1/13th COS Allocation Method

	Rate	Demand & Energy Component[1] $000s	Allocation	2017 WC3 Revenue Requirement Allocation @ 10.5% ROE
	(a)	(b)	(c)	(d)
1	CILC-1D	36,838	1.9%	$2,737,676
2	CILC-1G	1,435	0.1%	$106,656
3	CILC-1T	19,402	1.0%	$1,441,867
4	GS1	106,331	5.6%	$7,902,097
5	GSCU-1	910	0.0%	$67,649
6	GSD1	417,190	22.0%	$31,003,948
7	GSLD1	168,330	8.9%	$12,509,647
8	GSLD2	34,435	1.8%	$2,559,112
9	GSLD3	2,330	0.1%	$173,171
10	MET	1,452	0.1%	$107,943
11	OL-1	406	0.0%	$30,181
12	OS-2	139	0.0%	$10,334
13	RS1	1,101,385	58.1%	$81,850,650
14	SL-1	2,345	0.1%	$174,307
15	SL-2	424	0.0%	$31,539
16	SST-DST	175	0.0%	$13,021
17	SST-TST	1,018	0.1%	$75,682
18				
19	Total	1,894,548	100.0%	$140,795,481

Notes:
[1] Docket 160021-EI 2017 Test Year MFR E-6b attachment 2 of 2 lines 5 + 14 Other Production revenue requirements (12CP & 1/13th Method)

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY RECOVERY FACTOR FOR WEST COUNTY 3
JANUARY 2017 THROUGH DECEMBER 2017
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	57,063,506,058	-	-	$81,850,650		0.00143
2	GS1/GST1/WIES1	5,971,311,587	-	-	$7,902,097		0.00132
3	GSD1/GSDT1/HLFT1	25,836,330,536	50.15375%	70,567,469	$31,003,948	0.44	
4	OS2	10,793,313	-	-	$10,334		0.00096
5	GSLD1/GSLDT1/CS1/CST1/HLFT2	10,511,832,443	56.71170%	25,391,181	$12,509,647	0.49	
6	GSLD2/GSLDT2/CS2/CST2/HLFT3	2,516,449,511	65.79207%	5,239,524	$2,559,112	0.49	
7	GSLD3/GSLDT3/CS3/CST3	172,996,790	68.69783%	344,963	$173,171	0.50	
8	SST1T	89,667,754	11.31969%	1,085,123	$75,682		
9	SST1D1/SST1D2/SST1D3	11,856,926	29.68376%	54,718	$13,021		
10	CILC D/CILC G	2,789,895,442	74.14313%	5,154,590	$2,844,333	0.55	
11	CILC T	1,508,389,554	76.33683%	2,706,802	$1,441,867	0.53	
12	MET	91,208,296	64.64301%	193,281	$107,943	0.56	
13	OL1/SL1/PL1	658,751,104	-	-	$204,488		0.00031
14	SL2, GSCU1	103,004,444	-	-	$99,188		0.00096
		107,335,993,758		110,737,652	$140,795,481		

(1) Projected kwh sales for the period January 2017 through December 2017
(2) Billing kW Load Factor based on 2012-2014 load research data and 2016 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 FACTOR RDC ** ($/kw)	SDD ** ($/kw)
ISST1D	$0.06	$0.03
ISST1T	$0.06	$0.03
SST1T	$0.06	$0.03
SST1D1/SST1D2/SST1I	$0.06	$0.03

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF REVENUE IMPACT FOR WEST COUNTY 3
12CP & 1/13th COS Allocation Method

	(a)	Total Revenue[1] (b)	Total WC3 Costs (c)		% Increase (d)
1	RS1/RTR1	$5,452,009,987	$81,850,650		1.50%
2	GS1/GST1	$572,669,917	$7,902,097		1.38%
3	GSD1/GSDT1/HLFT1 (21-499 kW)	$2,007,139,401	$31,003,948		1.54%
4	OS2	$1,401,750	$10,334		0.74%
5	GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	$726,636,417	$12,509,647		1.72%
6	GSLD2/GSLDT2/CS2/CST2/HLFT3(2,000+ kW)	$160,635,608	$2,559,112		1.59%
7	GSLD3/GSLDT3/CS3/CST3	$10,332,049	$173,171		1.68%
8	ISST1D	$0	$0		0.00%
9	ISST1T	$0	$0		0.00%
10	SST1T	$7,290,651	$75,682		1.04%
11	SST1D1/SST1D2/SST1D3	$1,209,478	$13,021		1.08%
12	CILC D/CILC G	$157,825,087	$2,844,333		1.80%
13	CILC T	$72,613,947	$1,441,867		1.99%
14	MET	$7,187,414	$107,943		1.50%
15	OL1/SL1/PL1	$132,533,946	$204,488		0.15%
16	SL2, GSCU1	$9,174,223	$99,188		1.08%
17					
18	TOTAL	$9,318,659,875	$140,795,481		1.51%
				1.5x	2.27%
				Max	1.99%

Notes
1) Based on Projections of 2017 base and clause revenues.

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY
12CP AND 1/13th COS ALLOCATION
PAYMENT RECOVERY FACTOR
INCLUDING WEST COUNTY ENERGY CENTER UNIT 3

ESTIMATED FOR THE PERIOD OF: JANUARY 2017 THROUGH DECEMBER 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
RATE SCHEDULE	Jan 2017 - Dec 2017 Capacity Recovery Factor				2017 WCEC-3 Capacity Recovery Factor				Total Jan 2017 - Dec 2017 Capacity Recovery Factor			
	($KW)	($/kwh)	RDC ($/KW) [1]	SDD ($/KW) [2]	($KW)	($/kwh)	RDC ($/KW)	SDD ($/KW)	($KW)	($/kwh)	RDC ($/KW) [1]	SDD ($/KW) [2]
RS1/RTR1	-	0.00303	-	-	-	0.00143	-	-	-	0.00446	-	-
GS1/GST1	-	0.00278	-	-	-	0.00132	-	-	-	0.00410	-	-
GSD1/GSDT1/HLFT1	0.92	-	-	-	0.44	-	-	-	1.36	-	-	-
OS2	-	0.00201	-	-	-	0.00096	-	-	-	0.00297	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	1.03	-	-	-	0.49	-	-	-	1.52	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	1.01	-	-	-	0.49	-	-	-	1.50	-	-	-
GSLD3/GSLDT3/CS3/CST3	1.04	-	-	-	0.50	-	-	-	1.54	-	-	-
SST1T	-	-	$0.13	$0.06	-	-	$0.06	$0.03	-	-	$0.19	$0.09
SST1D1/SST1D2/SST1D3	-	-	$0.13	$0.06	-	-	$0.06	$0.03	-	-	$0.19	$0.09
CILC D/CILC G	1.14	-	-	-	0.55	-	-	-	1.69	-	-	-
CILC T	1.09	-	-	-	0.53	-	-	-	1.62	-	-	-
MET	1.17	-	-	-	0.56	-	-	-	1.73	-	-	-
OL1/SL1/PL1	-	0.00050	-	-	-	0.00031	-	-	-	0.00081	-	-
SL2, GSCU1	-	0.00197	-	-	-	0.00096	-	-	-	0.00293	-	-

[1] RDC=((Total Capacity Costs)/(Projected Avg 12CP @gen)(.10)(demand loss expansion factor))/12 months

[2] SDD=((Total Capacity Costs)/(Projected Avg 12 CP @gen)/(21 onpeak days)(demand loss expansion factor))/12 months

Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

APPENDIX VII
CAPACITY COST RECOVERY

2017 REVENUE REQUIREMENT CALCULATION FOR
WEST COUNTY ENERGY CENTER UNIT 3

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 25
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT & SUPPLEMENTAL)*Notice of Adoption of Terry J. Keith's testimony and exhibits by Renae B. Deaton, filed on October 3, 2016, (FPSC DN #07930-16).
DESCRIPTION: *R. B. Deaton TJK-8

TJK-8
DOCKET NO. 160001-EI
FPL WITNESS: TERRY J. KEITH
EXHIBIT _____
PAGES 1-2
SEPTEMBER 2, 2016

Line No.	WCEC3 Revenue Requirement Calculation	2017
1	Jurisdictional Adjusted Rate Base	$594,593,140
2	Rate of Return on Rate Base	8.701%
3	Required Jurisdictional Net Operating Income	51,735,906
4	Required Net Operating Income	51,735,906
5	Jurisdictional Adjusted Net Operating Income (Loss)	(34,424,439)
6	Net Operating Income Deficiency (Excess)	86,160,345
7	Net Operating Income Multiplier	1.63411
8	2017 Revenue Requirement	$140,795,481

Note:

The Rate of Return was calculated using the Settlement Agreement ROE of 10.5%, as approved in Order No. PSC-13-0023-S-EI.

Line No.	Capital Structure	Ratio	Cost Rate	Wtd Cost Rate	Pre Tax COC
1	Long Term Debt	44.200%	6.430%	2.84206%	2.84206%
2	Common Equity	55.800%	10.500%	5.85900%	9.53846%
3	Total	100.000%		8.70106%	12.38052%
4					
6					
7	**Assumptions**				
8	Income Tax Rate	38.575%			
9	Production Depreciation Rate	4.000%			
10	Transmission Depreciation Rate	2.500%			
11	Rate of Return	8.70106%			
12					
13					

14	**Net Plant**	**6/01/2011**	**12/31/2011**	**5/31/2012**	**12/31/2012**	**12/31/2013**	**12/31/2014**	**12/31/2015**	**12/31/2016**	**12/31/2017**
15	Production Plant	804,228,493	804,228,493	804,228,493	804,228,493	804,228,493	804,228,493	804,228,493	804,228,493	804,228,493
16	Transmission Plant	38,130,190	38,130,190	38,130,190	38,130,190	38,130,190	38,130,190	38,130,190	38,130,190	38,130,190
17	Production Reserve	0	(18,765,331)	(32,169,140)	(50,934,471)	(83,103,611)	(115,272,751)	(147,441,890)	(179,611,030)	(211,780,170)
18	Transmission Reserve	0	(556,065)	(953,255)	(1,509,320)	(2,462,575)	(3,415,830)	(4,369,084)	(5,322,339)	(6,275,594)
19	Deferred Taxes	10,263,153	5,327,263	(117,748)	(5,609,859)	(14,805,540)	(22,398,424)	(28,506,548)	(33,246,547)	(36,762,272)
20	Net Plant	852,621,836	828,364,549	809,118,540	784,305,033	741,986,957	701,271,678	662,041,160	624,178,767	587,540,647
21										
22										

23		**6/01/2011-12/31/2011**	**6/01/2011-5/31/2012**	**12/31/2011-12/31/2012**	**1/01/2012-5/31/2012**	**12/31/2012-12/31/2013**	**12/31/2013-12/31/2014**	**12/31/2014-12/31/2015**	**12/31/2015-12/31/2016**	**12/31/2016-12/31/2017**
24	**Average Rate Base**	840,493,193	830,870,188	806,334,791	804,228,493	763,145,995	721,629,318	681,656,419	643,109,963	605,859,707
25	Juris Factor	0.981404	0.981404	0.981404	0.981404	0.981404	0.981404	0.981404	0.981404	0.981404
26	**Juris Rate Base**	824,863,381	815,419,326	791,340,189	789,273,060	748,954,532	708,209,899	668,980,336	631,150,690	594,593,140
27										
28	**Juris Interest Expense**	13,675,149	23,174,706	22,490,363	9,346,506	21,285,737	20,127,750	19,012,823	17,937,681	16,898,694
29	**Income Tax - Interest Expense**	(5,275,189)	(8,939,643)	(8,675,658)	(3,605,415)	(8,210,973)	(7,764,280)	(7,334,196)	(6,919,461)	(6,518,671)
30										
31										

32	**Operating Expenses**	**6/01/2011-12/31/2011**	**6/01/2011-5/31/2012**	**12/31/2011-12/31/2012**	**1/01/2012-5/31/2012**	**12/31/2012-12/31/2013**	**12/31/2013-12/31/2014**	**12/31/2014-12/31/2015**	**12/31/2015-12/31/2016**	**12/31/2016-12/31/2017**
33	Other O&M - FOM, CAP, VOM, Prop Ins	11,077,697	19,109,938	19,382,875	8,032,241	19,760,595	19,745,545	19,745,545	20,952,145	21,369,245
34	Depreciation	19,321,397	33,122,394	33,122,394	13,800,998	33,122,394	33,122,394	33,122,394	33,122,394	33,122,394
35	Taxes Other Than Income Taxes - Prop Tax	8,641,892	14,566,253	14,218,468	6,069,272	13,622,265	13,026,062	12,429,859	11,833,656	11,237,453
36	Total Operating Expenses	39,040,986	66,798,586	66,723,737	27,902,511	66,505,254	65,894,001	65,297,798	65,908,195	65,729,092
37										
38	**Juris Operating Expenses**	38,307,070	65,542,755	65,469,103	27,377,901	65,254,414	64,654,538	64,069,422	64,667,606	64,491,536
39	**Income Tax - Operating Expenses**	(14,776,952)	(25,283,118)	(25,254,707)	(10,561,025)	(25,171,890)	(24,940,488)	(24,714,780)	(24,945,529)	(24,877,610)
40										
41	**Other Income Taxes**	790,050	1,354,370	1,354,370	564,320	1,354,370	1,354,370	1,354,370	1,354,370	1,354,370
42	**Juris Other Income Taxes**	775,358	1,329,184	1,329,184	553,826	1,329,184	1,329,184	1,329,184	1,329,184	1,329,184
43										
44										

45	**Juris Net Operating Income**	**6/01/2011-12/31/2011**	**6/01/2011-5/31/2012**	**12/31/2011-12/31/2012**	**1/01/2012-5/31/2012**	**12/31/2012-12/31/2013**	**12/31/2013-12/31/2014**	**12/31/2014-12/31/2015**	**12/31/2015-12/31/2016**	**12/31/2016-12/31/2017**
46	Operating Expenses	(38,307,070)	(65,542,755)	(65,469,103)	(27,377,901)	(65,254,414)	(64,654,538)	(64,069,422)	(64,667,606)	(64,491,536)
47	Income Tax - Operating Expenses	14,776,952	25,283,118	25,254,707	10,561,025	25,171,890	24,940,488	24,714,780	24,945,529	24,877,610
48	Income Tax - Interest Expense	5,275,189	8,939,643	8,675,658	3,605,415	8,210,973	7,764,280	7,334,196	6,919,461	6,518,671
49	Other Income Taxes	(775,358)	(1,329,184)	(1,329,184)	(553,826)	(1,329,184)	(1,329,184)	(1,329,184)	(1,329,184)	(1,329,184)
50	**Juris Net Operating Income**	(19,030,287)	(32,649,178)	(32,867,923)	(13,765,287)	(33,200,735)	(33,278,954)	(33,349,630)	(34,131,801)	(34,424,439)

APPENDIX III

FUEL COST RECOVERY

2015 INCENTIVE MECHANISM RESULTS

GJY-1
DOCKET NO. 160001-EI
FPL WITNESS: GERARD J. YUPP
PAGES 1-4
EXHIBIT ____
MARCH 2, 2016

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 26
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT & SUPPLEMENTAL)*Notice of Adoption of Terry J. Keith's testimony and exhibits by Renae B. Deaton, filed on October 3, 2016, (FPSC DN #07930-16).
DESCRIPTION: G. J. Yupp GJY-1

TOTAL GAINS SCHEDULE
Actual for the Period of: January 2015 through December 2015

TABLE 1

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Month	Wholesale Sales Gains ($)	Wholesale Purchases Savings ($)	Asset Optimization Gains ($)	Total Monthly Gains ($)	**Threshold 1** Gains ≤ $36M ($)	**Threshold 2** $36M > Gains ≤ $46M ($)	**Threshold 3** $46M > Gains ≤ $100M ($)	**Threshold 4** Gains > $100M ($)
				(2)+(3)+(4)				
January	7,808,996	0	1,382,983	9,191,978	9,191,978	0	0	0
February	8,534,224	33,880	2,108,498	10,676,602	10,676,602	0	0	0
March	2,560,883	528,348	1,327,720	4,416,951	4,416,951	0	0	0
April	140,759	1,455,363	1,065,146	2,661,268	2,661,268	0	0	0
May	658,291	525,620	1,098,629	2,282,540	2,282,540	0	0	0
June	477,652	3,252,160	885,670	4,615,482	4,615,482	0	0	0
July	511,813	968,258	898,360	2,378,432	2,155,178	223,253	0	0
August	441,575	941,364	752,095	2,135,034	0	2,135,034	0	0
September	378,727	720,821	848,241	1,947,789	0	1,947,789	0	0
October	498,991	313,083	894,303	1,706,377	0	1,706,377	0	0
November	373,729	744,544	883,821	2,002,095	0	2,002,095	0	0
December	1,012,262	94,168	1,763,400	2,869,830	0	1,985,452	884,377	0
Total	**23,397,901**	**9,577,611**	**13,908,866**	**46,884,377**	**36,000,000**	**10,000,000**	**884,377**	**0**

TABLE 2

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Month	**Threshold 1** Gains ≤ $36M 100% Customer Benefit ($)	**Threshold 2** $36M > Gains ≤ $46M 100% Customer Benefit ($)	**Threshold 3** $46M > Gains ≤ $100M 40% Customer Benefit ($)	**Threshold 3** $46M > 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	9,191,978	0	0	0	0	0	9,191,978	0
February	10,676,602	0	0	0	0	0	10,676,602	0
March	4,416,951	0	0	0	0	0	4,416,951	0
April	2,661,268	0	0	0	0	0	2,661,268	0
May	2,282,540	0	0	0	0	0	2,282,540	0
June	4,615,482	0	0	0	0	0	4,615,482	0
July	2,155,178	223,253	0	0	0	0	2,378,432	0
August	0	2,135,034	0	0	0	0	2,135,034	0
September	0	1,947,789	0	0	0	0	1,947,789	0
October	0	1,706,377	0	0	0	0	1,706,377	0
November	0	2,002,095	0	0	0	0	2,002,095	0
December	0	1,985,452	353,751	530,626	0	0	2,339,203	530,626
Total	**36,000,000**	**10,000,000**	**353,751**	**530,626**	**0**	**0**	**46,353,751**	**530,626**

WHOLESALE POWER DETAIL
Actual for the Period of: January 2015 through December 2015

Wholesale Sales - Table 1

(1) Month	(2) OS Wholesale Sales (MWh)	(3) FCBBS Wholesale Sales (MWh)	(4) Total Wholesale Sales (MWh)	(5) OS Gross Gains ($)	(6) FCBBS Gross Gains ($)	(7) Third-Party Transmission Costs ($)	(8) Incremental GT O&M Costs ($)	(9) Variable Power Plant O&M Costs ($)	(10) Power Option Premiums ($)	(11) Total Net Wholesale Sales Gains ($)
	Schedule A6	Schedule A6	(2) + (3)	Schedule A6	Schedule A6	Schedule A6	Schedule A6	Schedule A6	*CCRC	(5)+(6)+(7)+(8)+(9)
January	679,865	3,279	683,144	8,262,727	16,162	(325,942)	0	(157,809)	13,857	7,808,996
February	678,104	1,023	679,127	9,733,056	5,282	(344,663)	(12,808)	(888,185)	41,541	8,534,224
March	314,855	269	315,124	3,167,256	1,640	(180,634)	(2,346)	(438,890)	13,857	2,560,883
April	48,167	290	48,457	367,069	1,606	(131,963)	(36,192)	(73,170)	13,410	140,759
May	84,650	38	84,688	735,117	412	(14,269)	31,832	(127,879)	33,078	658,291
June	59,425	125	59,550	570,372	421	(803)	(15,826)	(89,921)	13,410	477,652
July	61,389	131	61,520	603,766	812	0	(13,727)	(92,895)	13,857	511,813
August	59,241	75	59,316	516,694	408	183	0	(89,567)	13,857	441,575
September	46,119	60	46,179	436,157	417	(3)	(1,525)	(69,730)	13,410	378,727
October	74,162	75	74,237	581,483	137	(47)	(984)	(112,098)	30,500	498,991
November	68,442	0	68,442	524,146	0	(42,412)	(4,658)	(103,347)	0	373,729
December	211,905	302	212,207	1,341,387	900	3,561	(13,153)	(320,433)	0	1,012,262
Total	**2,386,324**	**5,667**	**2,391,991**	**26,839,230**	**28,196**	**(1,036,992)**	**(69,386)**	**(2,563,924)**	**200,777**	**23,397,901**

Wholesale Purchases - Table 2

(1) Month	(2) OS Wholesale Purchases (MWh)	(3) FCBBS Wholesale Purchases (MWh)	(4) Total Wholesale Purchases (MWh)	(5) OS Savings ($)	(6) FCBBS Savings ($)	(7) Total Schedule A9 Savings ($)	(8) Capacity Purchases (MWh)	(9) Net Capacity Purchases Savings ($)	(10) Total Wholesale Purchases Savings ($)
	Schedule A9	Schedule A9	Schedule A9	Schedule A9	Schedule A9	Schedule A9	Schedule A7/A12		(7) + (9)
January	0	0	0	0	0	0	0	0	0
February	4,000	0	4,000	33,880	0	33,880	0	0	33,880
March	34,826	0	34,826	528,348	0	528,348	0	0	528,348
April	59,559	99	59,658	1,454,538	825	1,455,363	0	0	1,455,363
May	27,537	31	27,568	525,428	192	525,620	0	0	525,620
June	84,503	0	84,503	3,252,160	0	3,252,160	0	0	3,252,160
July	49,723	125	49,848	967,581	677	968,258	0	0	968,258
August	104,047	99	104,146	940,750	615	941,364	0	0	941,364
September	89,962	31	89,993	720,566	255	720,821	0	0	720,821
October	16,489	0	16,489	313,083	0	313,083	0	0	313,083
November	43,102	0	43,102	744,544	0	744,544	0	0	744,544
December	9,733	0	9,733	94,168	0	94,168	0	0	94,168
Total	**523,481**	**385**	**523,866**	**9,575,048**	**2,563**	**9,577,611**	**0**	**0**	**9,577,611**

*Capacity Cost Recovery Clause - Option premium gains are included under Transmission Revenues from Capacity Sales line item.

ASSET OPTIMIZATION DETAIL
Actual for the Period of: January 2015 through December 2015

(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) Natural Gas Storage Optimization ($)	(7) Natural Gas AMA Gains ($)	(8) Electric Transmission Capacity Release Firm Transmission ($)	(9) Total Asset Optimization Gains ($)
January								1,382,983
February								2,108,498
March								1,327,720
April								1,065,146
May								1,098,629
June								885,670
July								898,360
August								752,095
September								848,241
October								894,303
November								883,821
December								1,763,400
Total	**1,260,405**	**471,992**	**856,448**	**6,963,597**	**725,204**	**1,545,201**	**2,086,020**	**13,908,866**

INCREMENTAL OPTIMIZATION COSTS
Actual for the Period of: January 2015 through December 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Month	Personnel Expenses ($)	Other Expenses* ($)	Wholesale Sales (MWh)	Cumulative Wholesale Sales (MWh)	Wholesale Sales Threshold (MWh)	Wholesale Sales Above Threshold (MWh)	Incremental Variable O&M ($)	Total Incremental O&M Expenses ($)
	Schedule A2						Schedule A2	(2) + (3) + (8)
January	33,107	4,293	618,509	618,509	514,000	104,509	157,809	195,208
February	30,072	3,996	588,202	1,206,711	514,000	588,202	888,185	922,252
March	34,651	10,230	290,656	1,497,367	514,000	290,656	438,890	483,771
April	34,912	388	48,457	1,545,824	514,000	48,457	73,170	108,471
May	33,614	0	84,688	1,630,512	514,000	84,688	127,879	161,493
June	34,300	239	59,550	1,690,062	514,000	59,550	89,921	124,459
July	32,281	17	61,520	1,751,582	514,000	61,520	92,895	125,193
August	32,820	28,890	59,316	1,810,898	514,000	59,316	89,567	151,277
September	34,940	0	46,179	1,857,077	514,000	46,179	69,730	104,670
October	36,060	9,220	74,237	1,931,314	514,000	74,237	112,098	157,378
November	34,301	4,610	68,442	1,999,756	514,000	68,442	103,347	142,259
December	36,000	4,610	212,207	2,211,963	514,000	212,207	320,433	361,043
Total	**407,058**	**66,492**	**2,211,963**			**1,697,963**	**2,563,924**	**3,037,474**

*Includes software and hardware expenses

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	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	YEAR-TO-DATE (JAN - DEC) 2015	GAS RESERVES	[redacted]			[redacted]
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
8						$ (504,393,229)
9						
10						
11		AVERAGE PERIOD OF HEDGE (Years) - GAS RESERVES	[redacted]			
12		AVERAGE PERIOD OF HEDGE (Days) - FINANCIAL				

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 27
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT & SUPPLEMENTAL)*Notice of Adoption of Terry J. Keith's testimony and exhibits by Renae B. Deaton, filed on October 3, 2016, (FPSC DN #07930-16).
DESCRIPTION: G. J. Yupp GJY-2

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	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	January-2015	GAS RESERVES	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
8						
9						
10						
11						
12						

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	February-2015	GAS RESERVES	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
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12						

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	March-2015	GAS RESERVES	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
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12						

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	April-2015	GAS RESERVES	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
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12						

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2			VOLUME (MMBTU)			
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	May-2015	GAS RESERVES	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
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12						

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	June-2015	GAS RESERVES	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
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12						

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2			VOLUME (MMBTU)			
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	July-2015	GAS RESERVES	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
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CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	August-2015	GAS RESERVES	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
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CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	September-2015	GAS RESERVES	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
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12						

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2			VOLUME (MMBTU)			
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	October-2015	GAS RESERVES	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
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12						

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	November-2015	GAS RESERVES	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
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9						
10						
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12						

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2			VOLUME (MMBTU)			
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	December-2015	GAS RESERVES	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
8						
9						
10						
11						
12						

Results of FPL's Economic Evaluation[7]

PetroQuest[1]

	A	B	C	D	E	F = C + D + E	G = F / B	H	I = B x (H-G)	J	K = I x J	Change from Original Filing		
Period	Year	Annual Production (Bcf)[8]	Operating Expenses ($MM)	Depreciation ($MM)	Return Rate ($MM)[3]	Revenue Requirement ($MM)	Effective Cost ($/MMBtu)	FPL Market Price Forecast ($/MMBtu)[4]	Undiscounted Customer Savings ($MM)	FPL Discount Factor	Discounted Customer Savings ($MM)	Effective Cost ($/MMBtu)[5]	FPL Market Price Forecast ($/MMBtu)[6]	Discounted Savings Due to Decrease in Costs
1	2015	6.9	[redacted]				$3.90	$2.27	($11.3)	0.93	($10.5)	$0.42	($1.75)	$2.7
2	2016	17.2					$3.03	$2.40	($10.9)	0.86	($9.4)	($0.53)	($1.90)	($7.9)
3	2017	12.4					$3.21	$2.71	($6.3)	0.80	($5.0)	($0.78)	($2.00)	($7.8)
4	2018	9.2					$3.46	$2.83	($5.8)	0.75	($4.3)	($0.94)	($2.91)	($6.4)
5	2019	7.4					$3.86	$3.51	($2.6)	0.69	($1.8)	($1.10)	($2.37)	($5.7)
6	2020	6.3					$4.09	$3.60	($3.1)	0.64	($2.0)	($0.70)	($2.43)	($2.8)
7	2021	5.5					$4.32	$4.26	($0.4)	0.60	($0.2)	($0.62)	($1.88)	($2.0)
8	2022	4.9					$4.49	$4.52	$0.1	0.56	$0.1	($0.59)	($1.82)	($1.6)
9	2023	4.4					$4.64	$4.83	$0.9	0.52	$0.5	($0.57)	($1.80)	($1.3)
10	2024	4.1					$4.79	$5.42	$2.6	0.48	$1.2	($0.55)	($1.61)	($1.1)
11	2025	3.8					$4.71	$5.41	$2.6	0.45	$1.2	($0.53)	($1.92)	($0.9)
12	2026	3.5					$4.78	$5.39	$2.1	0.42	$0.9	($0.54)	($2.24)	($0.8)
13	2027	3.3					$4.85	$5.56	$2.3	0.39	$0.9	($0.54)	($2.37)	($0.7)
14	2028	3.1					$4.91	$5.74	$2.5	0.36	$0.9	($0.54)	($2.59)	($0.6)
15	2029	2.9					$4.99	$5.92	$2.7	0.33	$0.9	($0.53)	($2.71)	($0.5)
16	2030	2.7					$5.07	$6.11	$2.8	0.31	$0.9	($0.51)	($2.72)	($0.4)
17	2031	2.6					$5.15	$6.30	$2.9	0.29	$0.8	($0.50)	($2.87)	($0.4)
18	2032	2.4					$5.22	$6.50	$3.1	0.27	$0.8	($0.49)	($3.02)	($0.3)
19	2033	2.3					$5.32	$6.70	$3.1	0.25	$0.8	($0.48)	($3.18)	($0.3)
20	2034	2.1					$5.41	$6.84	$3.0	0.23	$0.7	($0.47)	($3.42)	($0.2)
21	2035	2.0					$5.51	$6.98	$2.9	0.22	$0.6	($0.46)	($3.67)	($0.2)
22	2036	1.9					$5.61	$7.21	$3.0	0.20	$0.6	($0.44)	($3.85)	($0.2)
23	2037-65	24.1					$7.85	$10.49	$63.8	0.10	$6.2	($0.04)	($6.66)	($0.1)
	Totals[2]	134.9	$312.6	$162.8	$169.1	$644.5			$60.2		($15.3)			($39.5)

Notes:

(1) Includes actuals through February 2016 and current estimates thereafter.

(2) Totals are for 2015-2065, an assumed 50 year project life. Totals may not add due to rounding.

(3) Return rate includes return on capital and return of capital.

(4) Utilizes FPL's January 2016 long-range forecast.

(5) Decrease in effective cost since filing due primarily to higher gross production estimates and lower cost to produce gas.

(6) Change in Market Price forecast since original filing.

(7) Guidelines IIA and IIB - Supplemental Information attached for additional analysis.

(8) Includes Btu conversion factor based on actual methane content.

Results of FPL's Economic Evaluation (Affiliate Transaction - US Gas Assets)

[redacted]

Period	Year	A Annual Production (Bcf)	B Operating Expenses ($MM)	C Depreciation ($MM)	D Return Rate[2] ($MM)	E Revenue Requirement ($MM)	F = C + D + E Effective Cost ($/MMBtu)[3]	G = F / B FPL Market Price Forecast [4]($/MMBtu)	H I = B x (H-G) Undiscounted Customer Savings[3] ($MM)	I FPL Discount Factor	J = I x J Discounted Customer Savings ($MM)
1	2015	0.2	[redacted]				$2.74	$2.14	($0.1)	0.97	($0.1)
2	2016	2.2					$2.56	$2.44	($0.3)	0.90	($0.2)
3	2017	1.3					$2.96	$2.76	($0.3)	0.84	($0.2)
4	2018	0.9					$3.33	$2.88	($0.4)	0.78	($0.3)
5	2019	0.7					$3.72	$3.57	($0.1)	0.73	($0.1)
6	2020	0.6					$3.98	$3.66	($0.2)	0.67	($0.1)
7	2021	0.5					$4.26	$4.31	$0.0	0.63	$0.0
8	2022	0.4					$4.50	$4.57	$0.0	0.58	$0.0
9	2023	0.4					$4.73	$4.89	$0.1	0.54	$0.0
10	2024	0.4					$4.98	$5.47	$0.2	0.50	$0.1
11	2025	0.3					$5.20	$5.46	$0.1	0.47	$0.0
12	2026	0.3					$5.40	$5.44	$0.0	0.44	$0.0
13	2027	0.3					$5.62	$5.61	($0.0)	0.41	($0.0)
14	2028	0.3					$5.83	$5.79	($0.0)	0.38	($0.0)
15	2029	0.2					$6.05	$5.97	($0.0)	0.35	($0.0)
16	2030	0.2					$6.26	$6.16	($0.0)	0.33	($0.0)
17	2031	0.2					$6.47	$6.35	($0.0)	0.30	($0.0)
18	2032	0.2					$6.68	$6.55	($0.0)	0.28	($0.0)
19	2033	0.2					$6.92	$6.75	($0.0)	0.26	($0.0)
20	2034	0.2					$7.16	$6.89	($0.0)	0.24	($0.0)
21	2035	0.2					$7.41	$7.03	($0.1)	0.23	($0.0)
22	2036	0.2					$7.68	$7.26	($0.1)	0.21	($0.0)
	2037-65	2.5					$14.28	$10.87	($8.5)	0.06	($0.5)
	Totals[1]	**13.0**	**$55.3**	**$12.9**	**$10.9**	**$79.1**			**($9.8)**		**($1.5)**

Notes:

(1) Totals are for 2015-2065, an assumed 50 year project life. Totals may not add due to rounding.

(2) Return rate includes return on capital and return of capital.

(3) Average conversion rate of 1 cubic foot = 1,000 btu's

(4) Utilizes FPL's January 2016 long-range forecast.

APPENDIX III

FUEL COST RECOVERY

WOODFORD REFUND CALCULATION

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 28
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT & SUPPLEMENTAL)*Notice of Adoption of Terry J. Keith's testimony and exhibits by Renae B. Deaton, filed on October 3, 2016, (FPSC DN #07930-16).
DESCRIPTION: G. J. Yupp GJY-3

GJY-3
DOCKET NO. 160001-EI
FPL WITNESS: GERARD J. YUPP
EXHIBIT _____
AUGUST 4, 2016

TABLE 1

Row	Mo-Yr	2015 FUEL FILING PROJECTIONS A: Total Projected Woodford Expenses ($)	B: Delivered to SESH Volume (MMBtu)	C: SESH Delivered Price ($/MMBtu)	2015 ACTUAL DATA D: Total Reserves Expenses ($)	E: Delivered to SESH Volume (MMBtu)	F: SESH Delivered Price ($/MMBtu)	MARKET DATA G: Columbia Gulf Mainline Index ($/MMBtu)	H: Total Market Cost of Gas ($)	TRUE-UP I: Monthly True-Up (Included in 2016 MCC) ($)	J: Refund (Hedging Activity Report) ($)	REFUND CALCULATION K: Cumulative Refund Balance ($)	L: Average Refund Balance ($)	M: Average Monthly Commercial Paper Rate (%)	N: Monthly Interest ($)	O: Total Refund ($)
1	Jan-15	$0	0	$0.0000	$0	0	$0.0000	$2.9189	$0	$0	$0	$0	$0		$0	$0
2	Feb-15	$0	0	$0.0000	$0	0	$0.0000	$2.8041	$0	$0	$0	$0	$0	0.00792%	$0	$0
3	Mar-15	$0	0	$0.0000	$476,186	72,945	$6.5280	$2.7276	$198,965	$476,186	($277,220)	($277,220)	($138,610)	0.00750%	($10)	($277,231)
4	Apr-15	$0	0	$0.0000	$665,756	52,896	$12.5861	$2.5150	$133,033	$665,756	($532,721)	($809,941)	($543,581)	0.00625%	($34)	($532,755)
5	May-15	$0	0	$0.0000	$707,473	57,768	$12.2468	$2.7747	$160,289	$707,473	($547,184)	($1,357,125)	($1,083,533)	0.00667%	($72)	($547,257)
6	Jun-15	$0	0	$0.0000	$1,693,026	245,427	$6.8983	$2.6912	$660,493	$1,693,026	($1,032,536)	($2,389,661)	($1,873,393)	0.00750%	($141)	($1,032,676)
7	Jul-15	$0	0	$0.0000	$1,780,514	456,247	$3.9025	$2.7774	$1,267,180	$1,780,514	($513,323)	($2,902,985)	($2,646,323)	0.00792%	($210)	($513,533)
8	Aug-15	$0	0	$0.0000	$4,472,007	1,019,972	$4.3844	$2.7134	$2,767,592	$4,472,007	($1,704,373)	($4,607,358)	($3,755,171)	0.00917%	($344)	($1,704,718)
9	Sep-15	$0	0	$0.0000	$3,374,346	904,446	$3.7308	$2.5682	$2,322,798	$3,374,346	($1,051,509)	($5,658,867)	($5,133,112)	0.01000%	($513)	($1,052,022)
10	Oct-15	$0	0	$0.0000	$4,290,744	1,216,490	$3.5272	$2.2582	$2,747,078	$4,290,744	($1,543,726)	($7,202,593)	($6,430,730)	0.01042%	($670)	($1,544,396)
11	Nov-15	$0	0	$0.0000	$4,680,801	1,305,443	$3.5856	$2.0067	$2,619,632	$4,680,801	($2,061,164)	($9,263,757)	($8,233,175)	0.01125%	($926)	($2,062,090)
12	Dec-15	$0	0	$0.0000	$4,844,491	1,585,219	$3.0560	$1.7998	$2,853,077	$4,844,491	($1,991,352)	($11,255,109)	($10,259,433)	0.02292%	($2,351)	($1,993,704)
13	**Total**	**$0**	**0**	**$0.0000**	**$26,985,345**	**6,916,853**	**$3.9014**	**$2.2742**	**$15,730,138**	**$26,985,345**	**($11,255,109)**				**($5,272)**	**($11,260,381)**

TABLE 2

Row	Mo-Yr	2016 FUEL FILING PROJECTIONS A: Total Reserves Expenses ($)	B: Delivered to SESH Volume (MMBtu)	C: SESH Delivered Price ($/MMBtu)	2016 ACTUAL DATA D: Total Reserves Expenses ($)	E: Delivered to SESH Volume (MMBtu)	F: SESH Delivered Price ($/MMBtu)	MARKET DATA G: *Columbia Gulf Mainline Index ($/MMBtu)	H: Total Market Cost of Gas ($)	TRUE-UP I: Actual Monthly True-Up (January - June) ($)	J: Estimated Monthly True-Up (July - December) ($)	K: Refund (Hedging Activity Report) ($)	REFUND CALCULATION L: Cumulative Refund Balance ($)	M: Average Refund Balance ($)	N: Average Monthly Commercial Paper Rate (%)	O: Monthly Interest ($)	P: Total Refund ($)
1	Jan-16	$5,905,286	2,204,117	$2.6792	$5,135,390	1,505,817	$3.4104	$2.2227	$3,346,979	($769,896)	$0	($1,788,459)	($13,043,568)	($12,149,338)	0.03333%	($4,049)	($1,792,508)
2	Feb-16	$5,612,561	2,038,350	$2.7535	$4,949,496	1,451,405	$3.4101	$1.8929	$2,747,365	($663,065)	$0	($2,202,072)	($15,245,639)	($14,144,603)	0.03417%	($4,833)	($2,206,905)
3	Mar-16	$5,515,140	1,949,433	$2.8291	$5,099,048	1,655,927	$3.0793	$1.6326	$2,703,466	($416,093)	$0	($2,395,630)	($17,641,269)	($16,443,454)	0.03583%	($5,892)	($2,401,521)
4	Apr-16	$5,232,321	1,821,145	$2.8731	$5,614,754	1,733,919	$3.2382	$1.8215	$3,158,333	$382,433	$0	($2,456,443)	($20,097,712)	($18,869,490)	0.03250%	($6,133)	($2,462,576)
5	May-16	$5,063,597	1,749,748	$2.8939	$5,532,116	1,968,705	$2.8100	$1.8237	$3,590,327	$468,519	$0	($1,941,734)	($22,039,446)	($21,068,579)	0.02917%	($6,146)	($1,947,879)
6	Jun-16	$4,814,459	1,649,726	$2.9183	$3,798,389	1,870,983	$2.0302	$2.4493	$4,582,599	($1,016,070)	$0	$784,129	($21,255,317)	($21,647,381)	0.03083%	($6,674)	$777,455
7	Jul-16	$4,619,748	1,566,526	$2.9490	$0	0	$0.0000	$2.8798	$4,511,282		($108,466)	$0				$0	$0
8	Aug-16	$4,492,838	1,520,109	$2.9556	$0	0	$0.0000	$2.7275	$4,146,097		($346,741)	$0				$0	$0
9	Sep-16	$4,262,047	1,425,199	$2.9905	$0	0	$0.0000	$2.7214	$3,878,537		($383,510)	$0				$0	$0
10	Oct-16	$4,169,419	1,389,795	$3.0000	$0	0	$0.0000	$2.7629	$3,839,865		($329,555)	$0				$0	$0
11	Nov-16	$4,005,405	1,325,176	$3.0225	$0	0	$0.0000	$2.9157	$3,863,816		($141,590)	$0				$0	$0
12	Dec-16	$3,882,280	1,251,879	$3.1012	$0	0	$0.0000	$3.1697	$3,968,081		$85,801	$0				$0	$0
13	**Total**	**$57,575,101**	**19,891,203**	**$2.8945**	**$30,129,193**	**10,186,756**	**$2.9577**	**$1.9760**	**$44,336,746**	**($2,014,171)**	**($1,224,061)**	**($10,000,208)**				**($33,726)**	**($10,033,934)**

TABLE 3

Line 1	Total Reserves Recovery	$84,560,446	TABLE 1 D13 + TABLE 2 A13
Line 2	Total Market Cost of Gas	$60,066,885	TABLE 1 H13 + TABLE 2 H13
Line 3	Total Amount Owed to Customers	$24,532,560	Line 1 - Line 2 (+ Interest)
Line 4	Total Market Value Refund (HAR)	($21,255,317)	TABLE 1 J13 + TABLE 2 K13
Line 5	Total Interest on Refund	($38,999)	TABLE 1 N13 + TABLE 2 O13
Line 6	Total Refund with Interest	($21,294,315)	Line 4 + Line 5
Line 7	January-June Total Actual True-Up	($2,014,171)	TABLE 2 I13
Line 8	July - December Estimated True-Up	($1,224,061)	TABLE 2 J13
Line 9	Rounding Difference	$13	Line 3 + Line 6 + Line 7 + Line 8

APPENDIX IV

FUEL COST RECOVERY

VOM CORRECTION REFUND

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 29
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT & SUPPLEMENTAL)*Notice of Adoption of Terry J. Keith's testimony and exhibits by Renae B. Deaton, filed on October 3, 2016, (FPSC DN #07930-16).
DESCRIPTION: G. J. Yupp GJY-4

GJY-4
DOCKET NO. 160001-EI
FPL WITNESS: GERARD J. YUPP
EXHIBIT _____
AUGUST 4, 2016

Month	Year	Sales Above Threshold (MWH)	Original VOM Rate ($/MWh)	VOM Collected ($)	Corrected VOM Rate ($/MWh)	Corrected VOM Collected ($)	Refund Amount ($)	Cumulative Refund Balance ($)	Average Refund Balance	Average Monthly Com Paper Rate	Monthly Interest	Total Refund
January	2013	0	1.51	$0	1.36	$0	$0	$0	$0	0.00583%	$0	$0
February	2013	0	1.51	$0	1.36	$0	$0	$0	$0	0.00792%	$0	$0
March	2013	246,784	1.51	$372,644	1.36	$335,626	($37,018)	($37,018)	($18,509)	0.00750%	($1)	($37,019)
April	2013	203,610	1.51	$307,451	1.36	$276,910	($30,541)	($67,559)	($52,288)	0.00667%	($3)	($30,545)
May	2013	150,864	1.51	$227,805	1.36	$205,175	($22,630)	($90,189)	($78,874)	0.00625%	($5)	($22,635)
June	2013	83,145	1.51	$125,549	1.36	$113,077	($12,472)	($102,660)	($96,425)	0.00542%	($5)	($12,477)
July	2013	103,009	1.51	$155,544	1.36	$140,092	($15,451)	($118,112)	($110,386)	0.00458%	($5)	($15,456)
August	2013	84,184	1.51	$127,118	1.36	$114,490	($12,628)	($130,739)	($124,426)	0.00458%	($6)	($12,633)
September	2013	88,010	1.51	$132,895	1.36	$119,694	($13,202)	($143,941)	($137,340)	0.00458%	($6)	($13,208)
October	2013	96,509	1.51	$145,729	1.36	$131,252	($14,476)	($158,417)	($151,179)	0.00417%	($6)	($14,483)
November	2013	185,332	1.51	$279,851	1.36	$252,052	($27,800)	($186,217)	($172,317)	0.00458%	($8)	($27,808)
December	2013	189,316	1.51	$285,867	1.36	$257,470	($28,397)	($214,614)	($200,416)	0.00583%	($12)	($28,409)
January	2014	(29,403.25)	1.51	(44,398.91)	1.36	(39,988.42)	$4,410	($210,204)	($212,409)	0.00625%	($13)	$4,397
February	2014	11,379	1.51	$17,182	1.36	$15,475	($1,707)	($211,911)	($211,057)	0.00542%	($11)	($1,718)
March	2014	311,531	1.51	$470,412	1.36	$423,682	($46,730)	($258,640)	($235,276)	0.00542%	($13)	($46,742)
April	2014	86,629	1.51	$130,810	1.36	$117,815	($12,994)	($271,635)	($265,138)	0.00625%	($17)	($13,011)
May	2014	93,060	1.51	$140,521	1.36	$126,562	($13,959)	($285,594)	($278,614)	0.00500%	($14)	($13,973)
June	2014	86,055	1.51	$129,943	1.36	$117,035	($12,908)	($298,502)	($292,048)	0.00417%	($12)	($12,920)
July	2014	79,428	1.51	$119,936	1.36	$108,022	($11,914)	($310,416)	($304,459)	0.00500%	($15)	($11,929)
August	2014	58,797	1.51	$88,783	1.36	$79,964	($8,820)	($319,236)	($314,826)	0.00542%	($17)	($8,837)
September	2014	90,295	1.51	$136,345	1.36	$122,801	($13,544)	($332,780)	($326,008)	0.00542%	($18)	($13,562)
October	2014	116,059	1.51	$175,249	1.36	$157,840	($17,409)	($350,189)	($341,484)	0.00542%	($19)	($17,427)
November	2014	312,471	1.51	$471,831	1.36	$424,961	($46,871)	($397,060)	($373,624)	0.00625%	($23)	($46,894)
December	2014	280,378	1.51	$423,371	1.36	$381,314	($42,057)	($439,116)	($418,088)	0.00750%	($31)	($42,088)
January	2015	104,509	1.51	$157,809	1.36	$142,132	($15,676)	($454,793)	($446,954)	0.00833%	($37)	($15,714)
February	2015	588,202	1.51	$888,185	1.36	$799,955	($88,230)	($543,023)	($498,908)	0.00792%	($40)	($88,270)
March	2015	290,656	1.51	$438,891	1.36	$395,292	($43,598)	($586,621)	($564,822)	0.00750%	($42)	($43,641)
April	2015	48,457	1.51	$73,170	1.36	$65,902	($7,269)	($593,890)	($590,256)	0.00625%	($37)	($7,305)
May	2015	84,688	1.51	$127,879	1.36	$115,176	($12,703)	($606,593)	($600,241)	0.00667%	($40)	($12,743)
June	2015	59,550	1.51	$89,921	1.36	$80,988	($8,933)	($615,526)	($611,059)	0.00750%	($46)	($8,978)
July	2015	61,520	1.51	$92,895	1.36	$83,667	($9,228)	($624,754)	($620,140)	0.00792%	($49)	($9,277)
August	2015	59,316	1.51	$89,567	1.36	$80,670	($8,897)	($633,651)	($629,202)	0.00917%	($58)	($8,955)
September	2015	46,179	1.51	$69,730	1.36	$62,803	($6,927)	($640,578)	($637,114)	0.01000%	($64)	($6,991)
October	2015	74,237	1.51	$112,098	1.36	$100,962	($11,136)	($651,713)	($646,146)	0.01042%	($67)	($11,203)
November	2015	68,442	1.51	$103,347	1.36	$93,081	($10,266)	($661,980)	($656,847)	0.01125%	($74)	($10,340)
December	2015	212,207	1.51	$320,433	1.36	$288,602	($31,831)	($693,811)	($677,895)	0.02292%	($155)	($31,986)
January	2016	872	1.51	$1,317	1.36	$1,186	($131)	($693,942)	($693,876)	0.03333%	($231)	($362)
February	2016	390,220	1.51	$589,232	1.36	$530,699	($58,533)	($752,475)	($723,208)	0.03417%	($247)	($58,780)
March	2016	179,253	1.51	$270,672	1.36	$243,784	($26,888)	($779,362)	($765,918)	0.03583%	($274)	($27,162)
April	2016	343,391	1.51	$518,520	1.36	$467,012	($51,509)	($830,871)	($805,117)	0.03250%	($262)	($51,770)
May	2016	147,987	1.36	$201,262	1.36	$201,262	$0	($830,871)	($830,871)	0.02917%	($242)	($242)
				$8,364,103		**$7,533,231**	**($830,871)**				**($1,985)**	**($832,856)**

APPENDIX V

FUEL COST RECOVERY

2017 RISK MANAGEMENT PLAN

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 30
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT & SUPPLEMENTAL)*Notice of Adoption of Terry J. Keith's testimony and exhibits by Renae B. Deaton, filed on October 3, 2016, (FPSC DN #07930-16).
DESCRIPTION: G. J. Yupp GJY-5

GJY-5
DOCKET NO. 160001-EI
FPL WITNESS: GERARD J. YUPP
EXHIBIT _____
AUGUST 4, 2016

APPENDIX V

2017 RISK MANAGEMENT PLAN

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1-7	2017 Risk Management Plan	G. J. Yupp
1-55	Trading and Risk Management Procedures Manual	G. J. Yupp
1-27	Energy Trading and Risk Management Policy	G. J. Yupp
1-20	Planned Position Strategy	G. J. Yupp

Florida Power and Light Company
2017 Risk Management Plan

Florida Power & Light ("FPL") recognizes the importance of managing price volatility in the fuel and power it purchases to provide electric service to its customers. Further, FPL recognizes that the greater the proportion of a particular energy source it relies upon to provide electric services to its customers, the greater the importance of managing price volatility associated with that energy source.

FPL's risk management plan is based on the following guiding principles:

a) A well-managed hedging program does not involve speculation or market timing. Its primary purpose is not to reduce FPL's fuel costs paid over time, but rather to reduce the variability or volatility in fuel costs over time.

b) Hedging can result in significant lost opportunities for savings in the fuel costs to be paid by customers if fuel prices actually settle at lower levels than at the time the hedges were placed. FPL does not predict or speculate on whether markets will ultimately rise or fall and actually settle higher or lower than the price levels that existed at the time hedges were put into place.

c) Market prices and forecasts of market prices have experienced significant volatility and are expected to continue to be highly volatile and, therefore, FPL does not intend to "outguess the market" in choosing the specific timing for effecting hedges or the percentage or volume of fuel hedged.

d) In order to balance the goal of reducing customers' exposure to rising fuel prices against the goal of allowing customers to benefit from falling fuel prices, it is appropriate to limit hedging to a portion of the total expected volume of fuel purchases.

Overall Quantitative and Qualitative Risk Management Objectives (TFB-4, Item 1)

FPL's risk management objectives are to effectively execute a well-disciplined and independently controlled fuel hedging strategy to achieve the goal of fuel price stability (volatility minimization). FPL's fuel hedging strategy aims to reduce fuel price volatility, while maintaining the opportunity to benefit from price decreases in the marketplace for FPL's customers.

Fuel Procurement Risks (TFB-4, Item 3)

FPL encounters several potential risks when executing its fuel procurement activities. These risks are grouped into four categories as detailed below:

Market Risk

Market Risk is the risk of changes in economic fair value due to fluctuations in market prices, volatility, correlation, and interest rates. Market risk has a direct impact on any open or unhedged energy positions.

Limits ("Limits") are set by the President and Chief Executive Officer ("CEO") of NextEra Energy ("NEE") and delegated to the Exposure Management Committee ("EMC"). The EMC establishes a forum for discussion of NEE's energy risk profile and operations and develops guidelines required for an appropriate risk management control infrastructure, which includes implementation and monitoring of compliance with the NextEra Energy Trading and Risk Management Policy ("Policy"). The EMC has in turn delegated limits to FPL Energy Marketing and Trading ("EMT") for specific portfolios.

Limits (collectively referred to as "Limits") are generally expressed in terms of:

- Maximum portfolio tenor; and
- Open (un-hedged) positions (where appropriate)

The FPL hedging program Limits will be managed in accordance with established corporate guidance. During the ordinary course of business, EMT management will have regard to these NEE Limits, such that pre-approval will be obtained before committing to transactions or contracts which might otherwise cause them to be breached. Adherence to Limits is monitored by the Risk Management Department.

Credit Risk

Credit risk management includes appropriate creditworthiness review and monitoring processes, the request for collateral if deemed necessary, and the inclusion of contractual risk mitigation terms and conditions whenever possible. Such credit risk mitigations include collateral threshold amounts, cross default amounts, payment netting, and set-off agreements. Credit Limits are typically established for trading transactions and are designed to manage counterparty credit risk; and set appropriate levels at which to trigger communication concerning risk and strategy.

During the ordinary course of business, EMT management adheres to these credit limits, such that pre-approval is obtained before committing to transactions or contracts which might otherwise cause the credit limits to be breached. Adherence to limits is monitored by the Risk Management Department, as well as dealmakers.

Liquidity Risk

Transacting Liquidity: The availability of market participants willing to transact or having credit quality to transact will have an impact on the utility's ability to execute hedging and risk management strategies.

Short-Term Funding Liquidity: Changes in underlying market parameters may impact movements of cash in relation to business activities. Positions that are balanced for fair value purposes, but unbalanced for cash flow purposes, may give rise to large swings in cash balances. Risk Management assists the Finance Department by analyzing and monitoring the sufficiency of the allocated portions of the corporate facilities as they relate to EMT liquidity requirements.

Operational Risk

Operating risk is the physical risk associated with maintaining and operating generation assets. The potential risks that FPL encounters with its physical fuel procurement are fuel supply and transportation availability, product quality, delivery timing, weather, environmental, and supplier failure to deliver.

There is also operational risk specific to the wholesale trading activities, relating to inaccurate records of assets and transactions ("Administrative Operational Risk"). Certain personnel are authorized to transact on behalf of FPL and in so doing, can obligate the entity "instantaneously." FPL maintains sufficient controls to ensure that information relating to commitments, obligations and assets are captured accurately, completely and on a timely basis.

Fuel Procurement Oversight/Policies and Procedures (TFB-4, Items 4, 5, 6, 7 and 9)

FPL provides its fuel procurement activities with independent oversight.

The President of FPL is responsible for authorizing all hedging activities. Changes in strategies and any deviations from the program are approved by the President of FPL or his designee prior to execution. Program activity is included in the Monthly Operations Performance Review ("MOPR") chaired by the CEO of NEE. In addition, the EMC reviews performance and current procurement/hedging activities on a monthly basis.

The utility is supported by an independent middle office Risk Management department that provides oversight of fuel procurement activities. FPL has formal Policy and Procedures documents, signed by all employees, which include controls specifically related to the fuels hedging program. The Risk Management department ensures that the approved execution strategies are followed for each program. Daily and monthly reports are generated and reviewed by the Risk Management department and distributed to various groups, including executive management. Credit reviews are performed by the Risk Management department and included in the reporting mentioned above. Execution strategies must be approved prior to the execution of any transactions and documented as a Planned Position Strategy ("PPS"). All hedge transactions are to be addressed within this strategy document per the ranges and percentages defined in the Risk Management Plan and may be modified from time to time.

Policy and Procedures

As part of this Risk Management Plan, FPL is attaching the latest Policy and Trading and Risk Management Procedures Manual ("Procedures"). NEE updates the Policy and Procedures as necessary. For details that are not covered in this document, please refer to the Policy and Procedures. FPL considers its Policy and Procedures to be confidential.

The NEE corporate risk Policy delineates individual and group transaction limits and authorizations for all fuel procurement activities. The Policy sets out the NEE approach to energy risk and the management of risk, as follows:

- Identification and definition;
- Quantification and measurements;
- Reporting;
- Authority to transact; and
- Ownership and roles and responsibilities.

The Procedures Manual provides guidance that will promote efficient and accurate processing of transactions, effective preparation and distribution of information relating to trading and marketing activities, and efficient monitoring of the portfolio of risks, all within a well-controlled environment.

FPL's deal execution and capture functions coordinate activities across relevant departments, personnel, and systems. This framework of activity properly links the responsibilities of personnel and provides a sufficient medium to resolve issues.

The Procedures clearly list authorized trading personnel, trading limits, tenors, and acceptable instruments. Access to the data entry privileges in the deal capture system is limited to only those individuals who are formally granted permissions to enter trades. All transactions are entered and managed through a centralized deal capture system that supports routine reporting, settlements, and review. Transaction record editing is managed through acceptable authorizations and processes. Credit information is available to traders on a timely basis through daily reporting produced by the Risk Management department. Auditable records of all transactions are maintained and subject to review on a regular basis.

Deal Execution Details

FPL traders receive daily credit reports and credit watch lists from the Risk Management department to ensure that FPL does not enter into a trade with an unauthorized counterparty. FPL traders then select counterparties from this list to transact with as the hedging program is executed. FPL uses a market comparison approach to execute financial hedges. For natural gas, real-time prices can be observed by FPL through electronic tools, such as ICE ("InterContinental Exchange"), FutureSource, or over-the-counter brokers.

FPL traders generally execute trades with counterparties offering the best price for a given instrument. However, in a case where two or more counterparties are offering similar pricing, the traders will attempt to execute trades with the counterparty that has the least amount of credit exposure with FPL. This is done primarily to allow FPL to spread its risk among as many counterparties as possible, but also affords the advantage of preventing the inadvertent telegraphing of FPL's commercial intentions to the market, thus helping to ensure favorable pricing for FPL's hedges.

2017 Hedging Strategy (TFB-4, Items 2 and 8)

FPL plans to hedge a portion of its projected 2018 natural gas requirements during 2017. Absent special circumstances (e.g. a hurricane that FPL concludes will substantially impair market functions); FPL will implement its hedging program within the following parameters:

1) FPL will hedge approximately [redacted] of its projected 2018 natural gas requirements from [redacted] through [redacted] ("the Hedging Window") using financial swaps, and/or physical fixed price transactions. This hedge percentage is a reduction from the 2017 hedge level and is within FPL's system base load requirements. FPL will hedge approximately [redacted] of each individual month's projected natural gas requirements. FPL will not financially hedge its projected natural gas requirements beyond the end of calendar year 2018.

2) This Hedging Window is the same as it was in the 2016 Risk Management Plan.

3) During each month of the Hedging Window, FPL will hedge between [redacted] and [redacted] of the target monthly volumes. This percentage range has been expanded from previous Risk Management Plans. FPL is expanding this range to provide more flexibility to make any necessary hedging adjustments. FPL will have flexibility within any given month to determine the appropriate timing for executing hedges.

4) FPL intends to rebalance its natural gas hedge positions during the year based on changes in forecasted market prices, projected unit outage schedules or changes in FPL's load forecast. Once the initial monthly target volumes have been hedged, rebalancing will be executed to maintain the hedge percentages inside approved tolerance bands. FPL will maintain an overall hedge percentage that falls within a [redacted] tolerance band. Therefore, the minimum and maximum monthly hedge percentages are [redacted] and [redacted] respectively.

5) FPL does not intend to hedge heavy fuel oil for 2018. FPL discontinued fuel oil hedging in 2013 and the factors that influenced that decision still remain.

Reporting System for Fuel Procurement Activities (TFB-4, Items 13 and 14)

FPL reporting systems comprehensively identify, measure, and monitor all forms of risk associated with fuel procurement activities.

FPL's philosophy on reporting is that it should be timely, consistent, flexible, and transparent. Timely and consistent reporting of risk information is critical to the effective management of risk. The utility has sufficient systems capability for identifying, measuring, and monitoring all types of risk associated with fuel procurement activities. These systems include: deal capture, current and historical pricing database, deal information, valuation models, and a reporting system that utilizes the information in the trade capture system and the database.

Specifically, several reports are available at FPL to monitor risk:

Daily Management Report

For each business day there is a formal report produced in hard copy or electronically, for distribution to business and desk heads and members of the EMC. This report details the current Mark to Market (spot and forward), unrealized Mark to Market changes, and VaR. This report is published only after proper and thorough discussion between Risk Management and desk heads, if necessary for clarification, and resolution of any issues raised.

Credit Exposure Reporting

For each business day there is a formal report produced in hard copy or electronically, for distribution to business and desk heads and members of the EMC. This report details:

- Allowable deal types by counterparty
- Restrictions on counterparties

EMC Update

The Vice President Trading Risk Management provides a formal update to the EMC on a monthly basis. The agenda for the update will be agreed in advance with the EMC Chairman, but at a minimum contains the following items:

- Summary and explanation of significant changes in market risk and fair value;
- Summary and explanation of significant changes in credit risk;
- Exceptions to Risk Management Policy; and
- Minutes of previous EMC update for approval.

Hedge Program Limitations (TFB-4, Item 15)

FPL does not currently have any limitations on implementing certain hedging techniques that would provide a net benefit to customers.

Summary Update on Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) on Utility Hedgers

FPL has reviewed the rules related to the Dodd-Frank Act and has implemented policies and procedures to comply with those rules that affect its business. FPL's fuel hedging program is classified as bona-fide hedging under such rules and therefore, FPL will be able to transact swaps in the over-the-counter market without being subject to mandatory clearing or mandatory margin requirements. However, FPL will still be subject to any margin requirements that its counterparties require.

FPL cannot predict the impact that all of these new rules will have on its ability to hedge its commodity risk or on the OTC derivatives market as a whole, but these rules could have a material effect on FPL's risk exposure and financial results.

Energy Marketing & Trading

A division of Florida Power & Light Company

Trading and Risk Management

Procedures Manual

Last Revision: ~~December 2015~~May 2016

REDACTED VERSION OF CONFIDENTIAL DOCUMENTS

[Pages 2 through 55]

Trading and Risk Management Procedures Manual

APPROVED BY THE EMC ON:

Last approved on January 6, 2016

Last Updated December 2015

(See EMC Emails noting approval. Please contact Risk Management at 304-6028)

NextEra Energy, Inc.
Energy Trading and Risk Management Policy

REDACTED VERSION OF CONFIDENTIAL DOCUMENTS

[Pages 2 through 27]

Energy Trading and Risk Management Policy

REDACTED VERSION OF CONFIDENTIAL DOCUMENTS

[Pages 1 through 20]

Planned Position Strategy

Florida Power and Light Company
2016 Risk Management Plan

Florida Power & Light ("FPL") recognizes the importance of managing price volatility in the fuel and power it purchases to provide electric service to its customers. Further, FPL recognizes that the greater the proportion of a particular energy source it relies upon to provide electric services to its customers, the greater the importance of managing price volatility associated with that energy source.

FPL's risk management plan is based on the following guiding principles:

a) A well-managed hedging program does not involve speculation or market timing. Its primary purpose is not to reduce FPL's fuel costs paid over time, but rather to reduce the variability or volatility in fuel costs over time.

b) Hedging can result in significant lost opportunities for savings in the fuel costs to be paid by customers if fuel prices actually settle at lower levels than at the time the hedges were placed. FPL does not predict or speculate on whether markets will ultimately rise or fall and actually settle higher or lower than the price levels that existed at the time hedges were put into place.

c) Market prices and forecasts of market prices have experienced significant volatility and are expected to continue to be highly volatile and, therefore, FPL does not intend to "outguess the market" in choosing the specific timing for effecting hedges or the percentage or volume of fuel hedged.

d) In order to balance the goal of reducing customers' exposure to rising fuel prices against the goal of allowing customers to benefit from falling fuel prices, it is appropriate to limit hedging to a portion of the total expected volume of fuel purchases.

Overall Quantitative and Qualitative Risk Management Objectives (TFB-4, Item 1)

FPL's risk management objectives are to effectively execute a well-disciplined and independently controlled fuel hedging strategy to achieve the goal of fuel price stability (volatility minimization). FPL's fuel hedging strategy aims to reduce fuel price volatility, while maintaining the opportunity to benefit from price decreases in the marketplace for FPL's customers.

Fuel Procurement Risks (TFB-4, Item 3)

FPL encounters several potential risks when executing its fuel procurement activities. These risks are grouped into four categories as detailed below:

Market Risk

Market Risk is the risk of changes in economic fair value due to fluctuations in market prices, volatility, correlation, and interest rates. Market risk has a direct impact on any open or unhedged energy positions.

Limits ("Limits") are set by the President and Chief Executive Officer ("CEO") of NextEra Energy ("NEE") and delegated to the Exposure Management Committee ("EMC"). The EMC establishes a forum for discussion of NEE's energy risk profile and operations and develops guidelines required for an appropriate risk management control infrastructure, which includes implementation and monitoring of compliance with the NextEra Energy Trading and Risk Management Policy ("Policy"). The EMC has in turn delegated limits to FPL Energy Marketing and Trading ("EMT") for specific portfolios.

Limits (collectively referred to as "Limits") are generally expressed in terms of:

- Maximum portfolio tenor; and
- Open (un-hedged) positions (where appropriate)

The FPL hedging program Limits will be managed in accordance with established corporate guidance. During the ordinary course of business, EMT management will have regard to these NEE Limits, such that pre-approval will be obtained before committing to transactions or contracts which might otherwise cause them to be breached. Adherence to Limits is monitored by the Risk Management Department.

Credit Risk

Credit risk management includes appropriate creditworthiness review and monitoring processes, the request for collateral if deemed necessary, and the inclusion of contractual risk mitigation terms and conditions whenever possible. Such credit risk mitigations include collateral threshold amounts, cross default amounts, payment netting, and set-off agreements. Credit Limits are typically established for trading transactions and are designed to manage counterparty credit risk; and set appropriate levels at which to trigger communication concerning risk and strategy.

During the ordinary course of business, EMT management adheres to these credit limits, such that pre-approval is obtained before committing to transactions or contracts which might otherwise cause the credit limits to be breached. Adherence to limits is monitored by the Risk Management Department, as well as dealmakers.

Liquidity Risk

Transacting Liquidity: The availability of market participants willing to transact or having credit quality to transact will have an impact on the utility's ability to execute hedging and risk management strategies.

Short-Term Funding Liquidity: Changes in underlying market parameters may impact movements of cash in relation to business activities. Positions that are balanced for fair value purposes, but unbalanced for cash flow purposes, may give rise to large swings in cash balances. Risk Management assists the Finance Department by analyzing and monitoring the sufficiency of the allocated portions of the corporate facilities as they relate to EMT liquidity requirements.

Operational Risk

Operating risk is the physical risk associated with maintaining and operating generation assets. The potential risks that FPL encounters with its physical fuel procurement are fuel supply and transportation availability, product quality, delivery timing, weather, environmental, and supplier failure to deliver.

There is also operational risk specific to the wholesale trading activities, relating to inaccurate records of assets and transactions ("Administrative Operational Risk"). Certain personnel are authorized to transact on behalf of FPL and in so doing, can obligate the entity "instantaneously." FPL maintains sufficient controls to ensure that information relating to commitments, obligations and assets are captured accurately, completely and on a timely basis.

Fuel Procurement Oversight/Policies and Procedures (TFB-4, Items 4, 5, 6, 7 and 9)

FPL provides its fuel procurement activities with independent oversight.

The President of FPL is responsible for authorizing all hedging activities. Changes in strategies and any deviations from the program are approved by the President of FPL or his designee prior to execution. Program activity is included in the Monthly Operations Performance Review ("MOPR") chaired by the CEO of NEE. In addition, the EMC reviews performance and current procurement/hedging activities on a monthly basis.

The utility is supported by an independent middle office Risk Management department that provides oversight of fuel procurement activities. FPL has formal Policy and Procedures documents, signed by all employees, which include controls specifically related to the fuels hedging program. The Risk Management department ensures that the approved execution strategies are followed for each program. Daily and monthly reports are generated and reviewed by the Risk Management department and distributed to various groups, including executive management. Credit reviews are performed by the Risk Management department and included in the reporting mentioned above. Execution strategies must be approved prior to the execution of any transactions and documented as a Planned Position Strategy ("PPS"). All hedge transactions are to be addressed within this strategy document per the ranges and percentages defined in the Risk Management Plan and may be modified from time to time.

Policy and Procedures

As part of this Risk Management Plan, FPL is attaching the latest Policy and Trading and Risk Management Procedures Manual ("Procedures"). NEE updates the Policy and Procedures as necessary. For details that are not covered in this document, please refer to the Policy and Procedures. FPL considers its Policy and Procedures to be confidential.

The NEE corporate risk Policy delineates individual and group transaction limits and authorizations for all fuel procurement activities. The Policy sets out the NEE approach to energy risk and the management of risk, as follows:

- Identification and definition;
- Quantification and measurements;
- Reporting;
- Authority to transact; and
- Ownership and roles and responsibilities.

The Procedures Manual provides guidance that will promote efficient and accurate processing of transactions, effective preparation and distribution of information relating to trading and marketing activities, and efficient monitoring of the portfolio of risks, all within a well-controlled environment.

FPL's deal execution and capture functions coordinate activities across relevant departments, personnel, and systems. This framework of activity properly links the responsibilities of personnel and provides a sufficient medium to resolve issues.

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FPL traders generally execute trades with counterparties offering the best price for a given instrument. However, in a case where two or more counterparties are offering similar pricing, the traders will attempt to execute trades with the counterparty that has the least amount of credit exposure with FPL. This is done primarily to allow FPL to spread its risk among as many counterparties as possible, but also affords the advantage of preventing the inadvertent telegraphing of FPL's commercial intentions to the market, thus helping to ensure favorable pricing for FPL's hedges.

2016 Hedging Strategy (TFB-4, Items 2 and 8)

Effective July 1, 2016, FPL's hedging strategy for its projected 2017 natural gas requirements will no longer include the Woodford Gas Reserves Project ("Woodford Project") that was approved in Order No. PSC-15-0038-FOF-EI, issued on January 12, 2015. Projected production volumes from the Woodford Project will not be incorporated as such in the percentage of natural gas that FPL hedges for the 2017 period.

Absent special circumstances (e.g. a hurricane that FPL concludes will substantially impair market functions); FPL will implement its hedging program within the following parameters:

1) FPL will hedge approximately [redacted] of its projected 2017 natural gas requirements within the Hedging Window during 2016 using financial swaps, and/or physical fixed price transactions. This hedge percentage is consistent with the 2016 hedge level and is within FPL's system base load requirements. FPL will hedge approximately [redacted] of each individual month's projected natural gas requirements. FPL will not financially hedge its projected natural gas requirements beyond the end of calendar year 2017.

2) FPL will execute its natural gas hedges for 2017 from [redacted] through [redacted] ("the Hedging Window"). This Hedging Window represents an expansion from previous Risk Management Plans.

3) During each month of the Hedging Window, FPL will hedge between [redacted] and [redacted] of the target monthly volumes. This percentage range has been expanded from previous Risk Management Plans. FPL is expanding this range to provide more flexibility to make any necessary hedging adjustments. FPL will have flexibility within any given month to determine the appropriate timing for executing hedges.

4) FPL intends to rebalance its natural gas hedge positions during the year based on changes in forecasted market prices, projected unit outage schedules or changes in FPL's load forecast. Once the initial monthly target volumes have been hedged, rebalancing will be executed to maintain the hedge percentages inside approved tolerance bands. FPL will maintain an overall hedge

percentage that falls within a [redacted] tolerance band. Therefore, the minimum and maximum monthly hedge percentages are [redacted] and [redacted] respectively.

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Hedge Program Limitations (TFB-4, Item 15)

FPL does not currently have any limitations on implementing certain hedging techniques that would provide a net benefit to customers.

Summary Update on Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) on Utility Hedgers

FPL has reviewed the rules related to the Dodd-Frank Act and has implemented policies and procedures to comply with those rules that affect its business.
FPL's fuel hedging program is classified as bona-fide hedging under the new rules and therefore, FPL will be able to transact swaps in the over-the-counter market without being subject to mandatory clearing.

FPL cannot predict the impact that all of these new rules will have on its ability to hedge its commodity risk or on the OTC derivatives market as a whole, but these rules could have a material effect on FPL's risk exposure and financial results. If the still-to-be-finalized margin rules require FPL to post significant amounts of cash collateral with respect to swap transactions, FPL's liquidity could be materially affected and its ability to enter into OTC derivatives to hedge commodity risks could be significantly limited.

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	YEAR-TO-DATE (JAN - JULY) 2016	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
8						$ (190,776,580)
9						
10						
11		AVERAGE PERIOD OF HEDGE (Days) - FINANCIAL	[redacted]			

NOTE: The January through July 2016 hedging results do not reflect the impact of the Woodford Gas Reserves Project. The Woodford results for the period, as detailed in Exhibit GJY-3, Table 2, included in FPL's Actual/Estimated filing made on August 4, 2016, were ($10,000,208).

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 31
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT & SUPPLEMENTAL)*Notice of Adoption of Terry J. Keith's testimony and exhibits by Renae B. Deaton, filed on October 3, 2016, (FPSC DN #07930-16).
DESCRIPTION: G. J. Yupp GJY-6

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	January-2016	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
8						
9						
10						
11						

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	February-2016	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
8						
9						
10						
11						

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	March-2016	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
8						
9						
10						
11						

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	April-2016	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
8						
9						
10						
11						

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	May-2016	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
8						
9						
10						
11						

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	June-2016	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
8						
9						
10						
11						

CONFIDENTIAL

	A	B	C	D	E	F
1				FPL NATURAL GAS PROCUREMENT		
2				VOLUME (MMBTU)		
3	**PERIOD**	**INSTRUMENT**	**PURCHASES**	**SALES**	**OPTION PREMIUMS**	**SAVINGS/(COSTS)**
4	July-2016	FIXED PRICE TRANSACTIONS	[redacted]			
5		SWAPS				
6		OVER-THE-COUNTER OPTIONS				
7		BROKER FEES				
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GJY-6
Docket No. 160001-EI
FPL Witness: Gerard J. Yupp
Page 8 of 8
August 18, 2016

APPENDIX I

FUEL COST RECOVERY

EXHIBIT GJY-7

DOCKET NO. 160001-EI

PAGES 1-4

SEPTEMBER 2, 2016

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 32
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT & SUPPLEMENTAL)*Notice of Adoption of Terry J. Keith's testimony and exhibits by Renae B. Deaton, filed on October 3, 2016, (FPSC DN #07930-16).
DESCRIPTION: G. J. Yupp GJY-7

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 Through December 2017

Heavy Oil	January	February	March	April	May	June	July	August	September	October	November	December
0.7% Sulfur Grade ($/Bbl)	49.40	49.75	50.10	50.40	50.84	51.14	51.44	51.74	52.04	52.20	52.50	52.80
0.7% Sulfur Grade ($/MMBtu)	7.72	7.77	7.83	7.88	7.94	7.99	8.04	8.08	8.13	8.16	8.20	8.25

Light Oil	January	February	March	April	May	June	July	August	September	October	November	December
Ultra-Low Sulfur Distillate ($/Bbl)	64.27	64.86	65.15	65.17	65.44	65.83	66.31	66.81	67.37	67.93	68.46	68.94
Ultra-Low Sulfur Distillate ($/MMBtu)	11.02	11.12	11.17	11.18	11.23	11.29	11.37	11.46	11.56	11.65	11.74	11.82

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	1,339,000	1,377,500	1,377,500	1,377,500	1,377,500	1,377,500	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	400,000	400,000
Total Projected Daily Availability (MMBtu/Day)	1,995,000	1,995,000	1,995,000	2,184,000	2,197,500	2,172,500	2,522,500	2,522,500	2,522,500	2,409,000	2,395,000	2,395,000
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 ($/MMBtu)	3.52	3.50	3.44	3.17	3.13	3.16	3.21	3.21	3.20	3.21	3.27	3.41
Firm Gulfstream ($/MMBtu)	3.45	3.43	3.36	3.08	3.03	3.07	3.12	3.12	3.10	3.12	3.19	3.33
Non-Firm FGT ($/MMBtu)	4.53	4.51	4.44	4.17	4.11	4.14	4.21	4.22	4.20	4.21	4.26	4.40
Non-Firm Gulfstream ($/MMBtu)	4.34	4.32	4.25	3.99	3.93	3.96	4.03	4.04	4.02	4.03	4.07	4.21

Coal	January	February	March	April	May	June	July	August	September	October	November	December
Scherer ($/MMBtu)	2.29	2.28	2.28	2.27	2.28	2.29	2.32	2.34	2.33	2.31	2.33	2.34
SJRPP ($/MMBtu)	2.07	2.07	2.07	2.05	2.05	2.05	2.04	2.04	2.04	2.04	2.05	2.05

FLORIDA POWER & LIGHT
PROJECTED UNIT AVAILABILITIES & OUTAGE SCHEDULES
PERIOD OF: JANUARY THROUGH DECEMBER, 2017

Plant/Unit	Forced Outage Factor (%)	Maintenance Outage Factor (%)	Planned Outage Factor (%)	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date	Overhaul Date
Cape Canaveral 3	0.7	5.5	10.1	02/15/17 - 03/23/17	03/25/17 - 04/30/17	11/13/17 - 12/19/17		
Ft. Myers 2	0.5	5.5	2.5	11/18/17 - 12/15/17				
Ft. Myers 3	1.0	3.5	1.9	04/01/17 - 04/07/17	12/02/17 - 12/08/17	12/09/17 - 12/15/17		
Ft. Myers 4 CTs	0.6	5.5	1.9	NONE				
Lauderdale 4	0.6	5.5	7.1	02/15/17 - 02/18/17	02/15/17 - 04/03/17			
Lauderdale 5	0.6	5.5	9.2	04/09/17 - 04/17/17	04/09/17 - 05/31/17	04/09/17 - 04/22/17		
Lauderdale CTs	1.0	3.5	1.9	11/06/17 - 11/12/17	11/13/17 - 11/19/17			
Manatee 1	0.3	3.5	7.7	03/04/17 - 03/31/17				
Manatee 2	0.2	3.5	2.7	11/04/17 - 11/13/17				
Manatee 3	0.3	4.6	24.9	03/04/17 - 05/02/17	03/18/17 - 05/16/17	03/25/17 - 05/23/17	03/25/17 - 06/05/17	05/20/17 - 07/18/17
Martin 1	0.2	3.5	0.0	03/04/17 - 03/13/17				
Martin 2	0.2	3.5	0.0	02/18/17 - 02/27/17				
Martin 3	0.4	5.5	2.3	03/14/17 - 03/20/17	03/14/17 - 03/23/17			
Martin 4	0.4	5.5	11.0	04/01/17 - 05/29/17	04/01/17 - 04/07/17	04/01/17 - 04/21/17		
Martin 8	0.6	5.1	21.5	01/01/17 - 02/07/17	01/07/17 - 03/07/17	01/07/17 - 03/24/17		
Port Everglades 5	1.0	5.5	3.8	10/07/17 - 10/20/17	12/02/17 - 12/15/17			
Riviera 5	0.7	5.5	0.0	04/15/17 - 04/24/17	04/25/17 - 05/04/17	05/05/17 - 05/14/17		
Sanford 4	0.4	5.5	10.1	05/06/17 - 05/12/17	07/22/17 - 09/14/17	07/29/17 - 09/21/17		
Sanford 5	0.4	5.5	10.1	02/18/17 - 02/24/17	05/20/17 - 07/18/17	06/03/17 - 08/01/17		
Scherer 4	1.5	3.5	0.0	NONE				
St. Johns 1	1.7	3.5	9.9	03/04/17 - 04/08/17				
St. Johns 2	1.7	3.5	2.2	02/20/17 - 02/27/17				
St. Lucie 1	1.2	1.2	0.0	NONE				
St. Lucie 2	1.1	1.1	9.9	02/20/17 - 03/28/17				
Turkey Point 3	1.1	1.1	8.5	03/27/17 - 04/27/17				
Turkey Point 4	1.1	1.1	8.2	10/02/17 - 11/01/17				
Turkey Point 5	0.4	5.5	17.7	09/09/17 - 11/07/17	09/23/17 - 11/21/17	10/28/17 - 12/26/17	11/04/17 - 11/13/17	
West County 1	0.5	5.5	2.7	02/25/17 - 03/06/17				
West County 2	0.5	5.5	0.0	NONE				
West County 3	0.5	5.0	17.1	04/08/17 - 05/30/17	10/21/17 - 12/12/17	10/29/17 - 12/20/17	11/01/17 - 11/28/17	

Florida Power and Light Company
Alternative 2017 Risk Management Plan

Florida Power & Light ("FPL") recognizes the importance of managing price volatility in the fuel and power it purchases to provide electric service to its customers. Further, FPL recognizes that the greater the proportion of a particular energy source it relies upon to provide electric services to its customers, the greater the importance of managing price volatility associated with that energy source.

However, on October 6, 2016, FPL, the Office of Public Counsel, the South Florida Hospital and Healthcare Association and the Florida Retail Federation jointly moved for approval of a proposed stipulation and settlement of FPL's rate case in Docket No. 160021-EI and consolidated dockets (the "Proposed Settlement Agreement"). The Proposed Settlement Agreement requires FPL to terminate natural gas financial hedging for the minimum term of the Agreement. Therefore, in accordance with Paragraph 16 of the Proposed Settlement Agreement, FPL will financially hedge 0% of its 2018 projected natural gas requirements.

FPL does not intend to hedge heavy fuel oil for 2018. FPL discontinued fuel oil hedging in 2013 and the factors that influenced that decision remain.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 33
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT & SUPPLEMENTAL)*Notice of Adoption of Terry J. Keith's testimony and exhibits by Renae B. Deaton, filed on October 3, 2016, (FPSC DN #07930-16).
DESCRIPTION: G. J. Yupp GJY-8

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2015

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 34
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT & SUPPLEMENTAL)*Notice of Adoption of Terry J. Keith's testimony and exhibits by Renae B. Deaton, filed on October 3, 2016, (FPSC DN #07930-16).
DESCRIPTION: C. R. Rote CRR-1

CRR-1
DOCKET NO. 160001-EI
FPL Witness: Charles R. Rote
Exhibit No.: _____
Pages 1 - 19
March 16, 2016

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2015

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 - 6.203.018	GPIF Units Points Tables
6.203.019	Planned Outages Schedule (Actual)

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ACTUAL)

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2015

GENERATNG PERFORMANCE INCENTIVE POINTS (GPIF)		FUEL SAVINGS/(LOSS) ($000)			GENERATING PERFORMANCE INCENTIVE FACTOR ($000)		
+ 10		115,905			56,491		
+ 9		104,315			50,842		
+ 8		92,724			45,193		
+ 7		81,134			39,544		
+ 6	<--------- 5.6041	69,543	<---------	64,959.390	33,895	<--------	31,658.059
+ 5		57,953			28,245		
+ 4		46,362			22,596		
+ 3		34,772			16,947		
+ 2		23,181			11,298		
+ 1		11,591			5,649		
0		0			0		
- 1		(11,591)			(5,649)		
- 2		(23,181)			(11,298)		
- 3		(34,772)			(16,947)		
- 4		(46,362)			(22,596)		
- 5		(57,953)			(28,245)		
- 6		(69,543)			(33,895)		
- 7		(81,134)			(39,544)		
- 8		(92,724)			(45,193)		
- 9		(104,315)			(50,842)		
- 10		(115,905)			(56,491)		

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ACTUAL

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2015

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 13,150,771,142	
LINE 2	MONTH OF January	2015	$ 13,850,484,435	
LINE 3	MONTH OF February	2015	$ 13,944,179,469	
LINE 4	MONTH OF March	2015	$ 14,059,999,048	
LINE 5	MONTH OF April	2015	$ 14,151,181,259	
LINE 6	MONTH OF May	2015	$ 14,321,231,458	
LINE 7	MONTH OF June	2015	$ 14,495,009,026	
LINE 8	MONTH OF July	2015	$ 14,682,602,474	
LINE 9	MONTH OF August	2015	$ 14,903,076,587	
LINE 10	MONTH OF September	2015	$ 15,888,109,822	
LINE 11	MONTH OF October	2015	$ 16,016,950,342	
LINE 12	MONTH OF November	2015	$ 16,149,652,871	
LINE 13	MONTH OF December	2015	$ 15,552,688,093	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 14,705,072,002	
LINE 15	25 BASIS POINTS		0.0025	
LINE 16	REVENUE EXPANSION FACTOR		61.3808%	
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$ 59,892,800	
LINE 18	JURISDICTIONAL SALES		109,820,399,000	KWH
LINE 19	TOTAL SALES		116,430,432,000	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		94.32%	
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$ 56,490,889	
LINE 22	INCENTIVE CAP (50 PECENT OF PROJECTED FUEL SAVINGS AT 10 GPIF·POINT LEVEL FROM SHEET NO. 3.515)		$ 57,952,500	
LINE 23	MAXIMUM ALLOWED GPIF REWARD (AT 10 GPIF-POINT LEVEL) (THE LESSER OF LINE 21 AND LINE 22)		$ 56,490,889	

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, 2015

DERIVATION OF SYSTEM ACTUAL GPIF POINTS

PLANT/UNIT	PERFORMANCE INDICATOR	WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
Ft. Myers 2	EAF	3.98	10.00	.3980
Ft. Myers 2	ANOHR	2.75	10.00	.2750
Martin 8	EAF	4.32	8.40	.3629
Martin 8	ANOHR	3.34	0.00	.0000
Manatee 3	EAF	3.73	10.00	.3730
Manatee 3	ANOHR	2.42	0.00	.0000
St. Lucie 1	EAF	8.89	10.00	.8890
St. Lucie 1	ANOHR	3.73	0.00	.0000
St. Lucie 2	EAF	7.32	6.67	.4882
St. Lucie 2	ANOHR	3.47	0.00	.0000
Turkey Point 3	EAF	7.30	10.00	.7300
Turkey Point 3	ANOHR	3.89	0.00	.0000
Turkey Point 4	EAF	8.04	10.00	.8040
Turkey Point 4	ANOHR	4.58	0.00	.0000
Turkey Point 5	EAF	4.77	10.00	.4770
Turkey Point 5	ANOHR	2.47	0.00	.0000
West County 1	EAF	4.61	10.00	.4610
West County 1	ANOHR	4.52	-1.69	-.0764
West County 2	EAF	4.91	10.00	.4910
West County 2	ANOHR	3.77	0.00	.0000
West County 3	EAF	3.41	1.50	.0512
West County 3	ANOHR	3.78	-3.17	-.1198
GPIF System Total:		100		5.6041

ACTUAL EQUIVALENT AVAILABILITY AND ADJUSTMENTS

JANUARY THROUGH DECEMBER, 2015

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							
Ft. Myers 2	0.3	2.3	18.0	79.3	7.3	86.6	84.1	10.00	04/11/15 - 05/24/15; 04/18/15 - 04/24/15 04/18/15 - 05/31/15; 05/30/15 - 07/05/15 06/06/15 - 07/19/15	11/14/15 - 11/30/15; 12/2/15 - 12/31/15 5/29/15 - 8/9/15; 10/14/15 - 12/10/15 8/14/15 - 10/13/15; 8/2/15 - 10/4/15 10/5/15 - 12/1/15; 12/3/15 - 12/4/15	4,621.0
Martin 8	0.1	4.9	7.4	87.6	-0.8	86.8	84.7	8.40	01/10/15 - 02/22/15; 02/07/15 - 02/22/15 02/07/15 - 03/22/15	2/3/15 - 2/25/15; 1/8/15 - 2/24/15 2/3/15 - 2/22/15; 2/2/15 - 2/22/15	4,202.5
Manatee 3	0.2	1.2	1.4	97.1	-1.4	95.7	90.3	10.00	07/13/15 - 07/19/15; 07/20/15 - 07/26/15 07/27/15 - 08/02/15	6/18/15 - 6/24/15; 6/18/15 - 6/23/15 6/18/15 - 6/24/15	4,322.0
St. Lucie 1	0.7	0.0	9.4	89.9	0.4	90.3	83.5	10.00	03/23/15 - 04/25/15	3/21/15 - 3/22/15; 3/22/15 - 4/27/15	10,302.0
St. Lucie 2	4.1	0.0	13.7	82.2	4.6	86.8	84.8	6.67	09/07/15 - 10/09/15	3/9/15 - 3/13/15; 4/30/15 9/6/15 - 10/28/15	5,660.2
Turkey Point 3	0.3	0.0	15.2	84.5	7.0	91.5	83.2	10.00	10/19/15 - 11/18/15	3/4/15 - 3/6/15; 4/29/15 - 5/5/15 8/16/15 - 8/19/15; 10/17/15 - 12/9/15	8,459.0
Turkey Point 4	0.8	0.0	1.1	98.1	1.1	99.2	93.6	10.00	NONE	5/7/15 - 5/12/15 and 5/15/15	9,317.0
Turkey Point 5	0.2	2.7	0.0	97.2	-2.3	94.9	91.1	10.00	06/06/15 - 06/10/15; 06/06/15 - 06/12/15 06/13/15 - 06/19/15	NONE	5,530.0
West County 1	0.7	4.1	2.3	92.8	-0.3	92.5	89.8	10.00	03/14/15 - 03/23/15	12/6/15 - 12/14/15; 12/6/15 - 12/13/15 12/3/15 - 12/13/15; 12/6/15 - 12/13/15	5,343.0
West County 2	1.2	3.9	14.1	80.8	1.1	81.9	78.8	10.00	03/14/15 - 03/20/15; 10/03/15 - 11/11/15 10/10/15 - 11/18/15; 10/16/15 - 11/11/15 10/16/15 - 11/24/15	10/10/15 - 11/29/15; 10/13/15 - 12/3/15 10/6/15 - 11/23/15; 10/7/15 - 11/24/15	5,692.0
West County 3	0.3	4.3	5.5	89.9	0.4	90.3	90.0	1.50	03/07/15 - 03/20/15; 03/14/15 - 03/20/15 09/05/15 - 09/19/15; 09/19/15 - 10/02/15	9/10/15 - 9/22/15; 11/6/15 - 11/12/15 9/23/15 - 10/5/15; 11/6/15 - 11/13/15 8/22/15 - 9/9/15; 11/6/15 - 11/12/15 11/6/15 - 11/12/15	593.3
											64,041.932

(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, 2015

	ACTUAL				TARGETS		ADJUSTED ACTUAL
PLANT / UNIT	PH	EFOH	EMOH	EPOH	POF%	EPOH	EAF%
Ft. Myers 2	8760	23.9	205.0	1580.3	10.6	928.0	86.6
Martin 8	8760	8.6	432.9	647.5	8.2	720.0	86.8
Manatee 3	8760	20.6	105.9	126.9	2.9	252.0	95.7
St. Lucie 1	8760	60.9	0.0	822.6	9.0	792.0	90.3
St. Lucie 2	8760	362.1	0.0	1199.9	8.8	768.0	86.8
Turkey Point 3	8760	23.6	0.0	1334.9	8.2	720.0	91.5
Turkey Point 4	8760	66.5	0.0	98.1	0.0	0.0	99.2
Turkey Point 5	8760	13.5	232.2	0.0	2.4	210.0	94.9
West County 1	8760	61.7	360.8	205.3	2.7	240.0	92.5
West County 2	8760	106.5	342.1	1232.5	12.9	1128.0	81.9
West County 3	8760	24.3	380.1	478.6	5.1	448.0	90.3

$$\text{ADJ. ACTUAL EAF\%} = 100\% - POF_T - \frac{(EFOH_A + EMOH_A) \times \frac{PH - EPOH_T}{PH - EPOH_A}}{PH} \times 100\%$$

ADJUSTMENTS TO AVERAGE NET OPERATING HEAT RATES & ADJUSTMENTS SUMMARY

JANUARY THROUGH DECEMBER, 2015

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
Ft. Myers 2	ANOHR=	-14.99	x NOF +	8,459		69.6	7,233	7,416	-183	7,197	7,014	10.00	3193.0
Martin 8	ANOHR=	-4.42	x NOF +	7,304		75.2	7,005	6,972	33	6,922	6,955	0.00	0.0
Manatee 3	ANOHR=	-3.91	x NOF +	7,287		79.2	6,948	6,977	-29	6,921	6,892	0.00	0.0
St. Lucie 1	ANOHR=	-25.19	x NOF +	12,884		100.8	10,340	10,345	-5	10,405	10,400	0.00	0.0
St. Lucie 2	ANOHR=	-11.92	x NOF +	11,463		101.1	10,209	10,258	-49	10,288	10,239	0.00	0.0
Turkey Point 3	ANOHR=	-10.96	x NOF +	12,226		98.1	11,134	11,151	-17	11,143	11,126	0.00	0.0
Turkey Point 4	ANOHR=	-6.72	x NOF +	11,666		99.6	10,989	10,997	-8	11,002	10,994	0.00	0.0
Turkey Point 5	ANOHR=	-6.11	x NOF +	7,573		76.1	7,050	7,108	-58	7,011	6,953	0.00	0.0
West County 1	ANOHR=	-5.36	x NOF +	7,287		66.7	7,016	6,929	87	6,794	6,881	-1.69	(884.5)
West County 2	ANOHR=	-4.58	x NOF +	7,275		72.0	6,950	6,945	5	6,866	6,871	0.00	0.0
West County 3	ANOHR=	-8.05	x NOF +	7,421		66.2	6,982	6,888	94	6,703	6,797	-3.17	(1391.0)

917.458

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.

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2015

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	4,621.0	<- Fuel Sav/(Loss) 4,621.0	86.6	<- Adj. Act. EAF= 86.6	+10	3,193.0	<- Fuel Sav/(Loss) 3,193.0	7,064	<- Adj. Act. HR=7,014
+9	4,158.9		86.4		+9	2,873.7		7,070	
+8	3,696.8		86.1		+8	2,554.4		7,076	
+7	3,234.7		85.9		+7	2,235.1		7,081	
+6	2,772.6		85.6		+6	1,915.8		7,087	
+5	2,310.5		85.4		+5	1,596.5		7,093	
+4	1,848.4		85.1		+4	1,277.2		7,099	
+3	1,386.3		84.9		+3	957.9		7,105	
+2	924.2		84.6		+2	638.6		7,110	
+1	462.1		84.4		+1	319.3		7,116	
						0		7,122	
0	0		84.1		0	0		7,197	
						0		7,272	
-1	(462.1)		83.9		-1	(319.3)		7,278	
-2	(924.2)		83.6		-2	(638.6)		7,284	
-3	(1,386.3)		83.4		-3	(957.9)		7,289	
-4	(1,848.4)		83.1		-4	(1,277.2)		7,295	
-5	(2,310.5)		82.9		-5	(1,596.5)		7,301	
-6	(2,772.6)		82.6		-6	(1,915.8)		7,307	
-7	(3,234.7)		82.4		-7	(2,235.1)		7,313	
-8	(3,696.8)		82.1		-8	(2,554.4)		7,318	
-9	(4,158.9)		81.9		-9	(2,873.7)		7,324	
-10	(4,621.0)		81.6		-10	(3,193.0)		7,330	
	WEIGHTING FACTOR =		3.98			WEIGHTING FACTOR =		2.75	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2015

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	5,003.0		87.2		+10	3,875.0		6,789	
+9	4,502.7		87.0		+9	3,487.5		6,795	
+8	4,002.4	<- Fuel Sav/(Loss) 4.202.5	86.7	<- Adj. Act. EAF= 86.8	+8	3,100.0		6,801	
+7	3,502.1		86.5		+7	2,712.5		6,806	
+6	3,001.8		86.2		+6	2,325.0		6,812	
+5	2,501.5		86.0		+5	1,937.5		6,818	
+4	2,001.2		85.7		+4	1,550.0		6,824	
+3	1,500.9		85.5		+3	1,162.5		6,830	
+2	1,000.6		85.2		+2	775.0		6,835	
+1	500.3		85.0		+1	387.5		6,841	
						0		6,847	
0	0		84.7		0	0	<- Fuel Sav/(Loss)	6,922	<- Adj. Act. HR=6.955
						0		6,997	
-1	(500.3)		84.5		-1	(387.5)		7,003	
-2	(1,000.6)		84.2		-2	(775.0)		7,009	
-3	(1,500.9)		84.0		-3	(1,162.5)		7,014	
-4	(2,001.2)		83.7		-4	(1,550.0)		7,020	
-5	(2,501.5)		83.5		-5	(1,937.5)		7,026	
-6	(3,001.8)		83.2		-6	(2,325.0)		7,032	
-7	(3,502.1)		83.0		-7	(2,712.5)		7,038	
-8	(4,002.4)		82.7		-8	(3,100.0)		7,043	
-9	(4,502.7)		82.5		-9	(3,487.5)		7,049	
-10	(5,003.0)		82.2		-10	(3,875.0)		7,055	
	WEIGHTING FACTOR =		4.32			WEIGHTING FACTOR =		3.34	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2015

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	4,322.0	<- Fuel Sav/(Loss) 4,322.0	92.8	<- Adj. Act. EAF= 95.7	+10	2,802.0		6,804	
+9	3,889.8		92.6		+9	2,521.8		6,808	
+8	3,457.6		92.3		+8	2,241.6		6,812	
+7	3,025.4		92.1		+7	1,961.4		6,817	
+6	2,593.2		91.8		+6	1,681.2		6,821	
+5	2,161.0		91.6		+5	1,401.0		6,825	
+4	1,728.8		91.3		+4	1,120.8		6,829	
+3	1,296.6		91.1		+3	840.6		6,833	
+2	864.4		90.8		+2	560.4		6,838	
+1	432.2		90.6		+1	280.2		6,842	
						0	<- Fuel Sav/(Loss)	6,846	<- Adj. Act. HR=6,892
0	0		90.3		0	0		6,921	
						0		6,996	
-1	(432.2)		90.1		-1	(280.2)		7,000	
-2	(864.4)		89.8		-2	(560.4)		7,004	
-3	(1,296.6)		89.6		-3	(840.6)		7,009	
-4	(1,728.8)		89.3		-4	(1,120.8)		7,013	
-5	(2,161.0)		89.1		-5	(1,401.0)		7,017	
-6	(2,593.2)		88.8		-6	(1,681.2)		7,021	
-7	(3,025.4)		88.6		-7	(1,961.4)		7,025	
-8	(3,457.6)		88.3		-8	(2,241.6)		7,030	
-9	(3,889.8)		88.1		-9	(2,521.8)		7,034	
-10	(4,322.0)		87.8		-10	(2,802.0)		7,038	
	WEIGHTING FACTOR =		3.73			WEIGHTING FACTOR =		2.42	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2015

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	10,302.0	<- Fuel Sav/(Loss) 10,302.0	86.5	<- Adj. Act. EAF= 90.3	+10	4,324.0		10,277	
+9	9,271.8		86.2		+9	3,891.6		10,282	
+8	8,241.6		85.9		+8	3,459.2		10,288	
+7	7,211.4		85.6		+7	3,026.8		10,293	
+6	6,181.2		85.3		+6	2,594.4		10,298	
+5	5,151.0		85.0		+5	2,162.0		10,304	
+4	4,120.8		84.7		+4	1,729.6		10,309	
+3	3,090.6		84.4		+3	1,297.2		10,314	
+2	2,060.4		84.1		+2	864.8		10,319	
+1	1,030.2		83.8		+1	432.4		10,325	
						0	<- Fuel Sav/(Loss)	10,330	<- Adj. Act. HR=10,400
0	0		83.5		0	0		10,405	
						0		10,480	
-1	(1,030.2)		83.2		-1	(432.4)		10,485	
-2	(2,060.4)		82.9		-2	(864.8)		10,491	
-3	(3,090.6)		82.6		-3	(1,297.2)		10,496	
-4	(4,120.8)		82.3		-4	(1,729.6)		10,501	
-5	(5,151.0)		82.0		-5	(2,162.0)		10,507	
-6	(6,181.2)		81.7		-6	(2,594.4)		10,512	
-7	(7,211.4)		81.4		-7	(3,026.8)		10,517	
-8	(8,241.6)		81.1		-8	(3,459.2)		10,522	
-9	(9,271.8)		80.8		-9	(3,891.6)		10,528	
-10	(10,302.0)		80.5		-10	(4,324.0)		10,533	
	WEIGHTING FACTOR =		8.89			WEIGHTING FACTOR =		3.73	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2015

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	8,486.0		87.8		+10	4,019.0		10,142	
+9	7,637.4		87.5		+9	3,617.1		10,149	
+8	6,788.8		87.2		+8	3,215.2		10,156	
+7	5,940.2		86.9		+7	2,813.3		10,163	
+6	5,091.6	<- Fuel Sav/(Loss) 5.660.2	86.6	<- Adj. Act. EAF= 86.8	+6	2,411.4		10,170	
+5	4,243.0		86.3		+5	2,009.5		10,178	
+4	3,394.4		86.0		+4	1,607.6		10,185	
+3	2,545.8		85.7		+3	1,205.7		10,192	
+2	1,697.2		85.4		+2	803.8		10,199	
+1	848.6		85.1		+1	401.9		10,206	
						0	<- Fuel Sav/(Loss)	10,213	<- Adj. Act. HR=10.239
0	0		84.8		0	0		10,288	
						0		10,363	
-1	(848.6)		84.5		-1	(401.9)		10,370	
-2	(1,697.2)		84.2		-2	(803.8)		10,377	
-3	(2,545.8)		83.9		-3	(1,205.7)		10,384	
-4	(3,394.4)		83.6		-4	(1,607.6)		10,391	
-5	(4,243.0)		83.3		-5	(2,009.5)		10,399	
-6	(5,091.6)		83.0		-6	(2,411.4)		10,406	
-7	(5,940.2)		82.7		-7	(2,813.3)		10,413	
-8	(6,788.8)		82.4		-8	(3,215.2)		10,420	
-9	(7,637.4)		82.1		-9	(3,617.1)		10,427	
-10	(8,486.0)		81.8		-10	(4,019.0)		10,434	
	WEIGHTING FACTOR =		7.32			WEIGHTING FACTOR =		3.47	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2015

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	8,459.0	<- Fuel Sav/(Loss) 8,459.0	86.2	<- Adj. Act. EAF= 91.5	+10	4,506.0		10,972	
+9	7,613.1		85.9		+9	4,055.4		10,982	
+8	6,767.2		85.6		+8	3,604.8		10,991	
+7	5,921.3		85.3		+7	3,154.2		11,001	
+6	5,075.4		85.0		+6	2,703.6		11,010	
+5	4,229.5		84.7		+5	2,253.0		11,020	
+4	3,383.6		84.4		+4	1,802.4		11,030	
+3	2,537.7		84.1		+3	1,351.8		11,039	
+2	1,691.8		83.8		+2	901.2		11,049	
+1	845.9		83.5		+1	450.6		11,058	
						0	<- Fuel Sav/(Loss)	11,068	<- Adj. Act. HR=11,126
0	0		83.2		0	0		11,143	
						0		11,218	
-1	(845.9)		82.9		-1	(450.6)		11,228	
-2	(1,691.8)		82.6		-2	(901.2)		11,237	
-3	(2,537.7)		82.3		-3	(1,351.8)		11,247	
-4	(3,383.6)		82.0		-4	(1,802.4)		11,256	
-5	(4,229.5)		81.7		-5	(2,253.0)		11,266	
-6	(5,075.4)		81.4		-6	(2,703.6)		11,276	
-7	(5,921.3)		81.1		-7	(3,154.2)		11,285	
-8	(6,767.2)		80.8		-8	(3,604.8)		11,295	
-9	(7,613.1)		80.5		-9	(4,055.4)		11,304	
-10	(8,459.0)		80.2		-10	(4,506.0)		11,314	
	WEIGHTING FACTOR =		7.30			WEIGHTING FACTOR =		3.89	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2015

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	9,317.0	<- Fuel Sav/(Loss) 9,317.0	96.6	<- Adj. Act. EAF= 99.2	+10	5,305.0		10,746	
+9	8,385.3		96.3		+9	4,774.5		10,764	
+8	7,453.6		96.0		+8	4,244.0		10,782	
+7	6,521.9		95.7		+7	3,713.5		10,800	
+6	5,590.2		95.4		+6	3,183.0		10,818	
+5	4,658.5		95.1		+5	2,652.5		10,837	
+4	3,726.8		94.8		+4	2,122.0		10,855	
+3	2,795.1		94.5		+3	1,591.5		10,873	
+2	1,863.4		94.2		+2	1,061.0		10,891	
+1	931.7		93.9		+1	530.5		10,909	
						0	<- Fuel Sav/(Loss)	10,927	<- Adj. Act. HR=10,994
0	0		93.6		0	0		11,002	
						0		11,077	
-1	(931.7)		93.3		-1	(530.5)		11,095	
-2	(1,863.4)		93.0		-2	(1,061.0)		11,113	
-3	(2,795.1)		92.7		-3	(1,591.5)		11,131	
-4	(3,726.8)		92.4		-4	(2,122.0)		11,149	
-5	(4,658.5)		92.1		-5	(2,652.5)		11,168	
-6	(5,590.2)		91.8		-6	(3,183.0)		11,186	
-7	(6,521.9)		91.5		-7	(3,713.5)		11,204	
-8	(7,453.6)		91.2		-8	(4,244.0)		11,222	
-9	(8,385.3)		90.9		-9	(4,774.5)		11,240	
-10	(9,317.0)		90.6		-10	(5,305.0)		11,258	
	WEIGHTING FACTOR =		8.04			WEIGHTING FACTOR =		4.58	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2015

UNIT: Turkey Point 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	5,530.0	<- Fuel Sav/(Loss) 5,530.0	93.6	<- Adj. Act. EAF= 94.9	+10	2,862.0		6,861	
+9	4,977.0		93.4		+9	2,575.8		6,869	
+8	4,424.0		93.1		+8	2,289.6		6,876	
+7	3,871.0		92.9		+7	2,003.4		6,884	
+6	3,318.0		92.6		+6	1,717.2		6,891	
+5	2,765.0		92.4		+5	1,431.0		6,899	
+4	2,212.0		92.1		+4	1,144.8		6,906	
+3	1,659.0		91.9		+3	858.6		6,914	
+2	1,106.0		91.6		+2	572.4		6,921	
+1	553.0		91.4		+1	286.2		6,929	
						0	<- Fuel Sav/(Loss)	6,936	<- Adj. Act. HR=6,953
0	0		91.1		0	0		7,011	
						0		7,086	
-1	(553.0)		90.9		-1	(286.2)		7,094	
-2	(1,106.0)		90.6		-2	(572.4)		7,101	
-3	(1,659.0)		90.4		-3	(858.6)		7,109	
-4	(2,212.0)		90.1		-4	(1,144.8)		7,116	
-5	(2,765.0)		89.9		-5	(1,431.0)		7,124	
-6	(3,318.0)		89.6		-6	(1,717.2)		7,131	
-7	(3,871.0)		89.4		-7	(2,003.4)		7,139	
-8	(4,424.0)		89.1		-8	(2,289.6)		7,146	
-9	(4,977.0)		88.9		-9	(2,575.8)		7,154	
-10	(5,530.0)		88.6		-10	(2,862.0)		7,161	
	WEIGHTING FACTOR =		4.77			WEIGHTING FACTOR =		2.47	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2015

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	5,343.0	<- Fuel Sav/(Loss) 5,343.0	92.3	<- Adj. Act. EAF= 92.5	+10	5,234.0		6,648	
+9	4,808.7		92.1		+9	4,710.6		6,655	
+8	4,274.4		91.8		+8	4,187.2		6,662	
+7	3,740.1		91.6		+7	3,663.8		6,669	
+6	3,205.8		91.3		+6	3,140.4		6,676	
+5	2,671.5		91.1		+5	2,617.0		6,684	
+4	2,137.2		90.8		+4	2,093.6		6,691	
+3	1,602.9		90.6		+3	1,570.2		6,698	
+2	1,068.6		90.3		+2	1,046.8		6,705	
+1	534.3		90.1		+1	523.4		6,712	
						0		6,719	
0	0		89.8		0	0		6,794	
						0		6,869	
-1	(534.3)		89.6		-1	(523.4)	<- Fuel Sav/(Loss) -884.5	6,876	<- Adj. Act. HR=6,881
-2	(1,068.6)		89.3		-2	(1,046.8)		6,883	
-3	(1,602.9)		89.1		-3	(1,570.2)		6,890	
-4	(2,137.2)		88.8		-4	(2,093.6)		6,897	
-5	(2,671.5)		88.6		-5	(2,617.0)		6,905	
-6	(3,205.8)		88.3		-6	(3,140.4)		6,912	
-7	(3,740.1)		88.1		-7	(3,663.8)		6,919	
-8	(4,274.4)		87.8		-8	(4,187.2)		6,926	
-9	(4,808.7)		87.6		-9	(4,710.6)		6,933	
-10	(5,343.0)		87.3		-10	(5,234.0)		6,940	
	WEIGHTING FACTOR =		4.61			WEIGHTING FACTOR =		4.52	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2015

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	5,692.0	<- Fuel Sav/(Loss) 5,692.0	81.8	<- Adj. Act. EAF= 81.9	+10	4,367.0		6,726	
+9	5,122.8		81.5		+9	3,930.3		6,733	
+8	4,553.6		81.2		+8	3,493.6		6,739	
+7	3,984.4		80.9		+7	3,056.9		6,746	
+6	3,415.2		80.6		+6	2,620.2		6,752	
+5	2,846.0		80.3		+5	2,183.5		6,759	
+4	2,276.8		80.0		+4	1,746.8		6,765	
+3	1,707.6		79.7		+3	1,310.1		6,772	
+2	1,138.4		79.4		+2	873.4		6,778	
+1	569.2		79.1		+1	436.7		6,785	
						0		6,791	
0	0		78.8		0	0	<- Fuel Sav/(Loss)	6,866	<- Adj. Act. HR=6,871
						0		6,941	
-1	(569.2)		78.5		-1	(436.7)		6,948	
-2	(1,138.4)		78.2		-2	(873.4)		6,954	
-3	(1,707.6)		77.9		-3	(1,310.1)		6,961	
-4	(2,276.8)		77.6		-4	(1,746.8)		6,967	
-5	(2,846.0)		77.3		-5	(2,183.5)		6,974	
-6	(3,415.2)		77.0		-6	(2,620.2)		6,980	
-7	(3,984.4)		76.7		-7	(3,056.9)		6,987	
-8	(4,553.6)		76.4		-8	(3,493.6)		6,993	
-9	(5,122.8)		76.1		-9	(3,930.3)		7,000	
-10	(5,692.0)		75.8		-10	(4,367.0)		7,006	
	WEIGHTING FACTOR =		4.91			WEIGHTING FACTOR =		3.77	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2015

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	3,955.0	92.0	+10	4,388.0	6,568
+9	3,559.5	91.8	+9	3,949.2	6,574
+8	3,164.0	91.6	+8	3,510.4	6,580
+7	2,768.5	91.4	+7	3,071.6	6,586
+6	2,373.0	91.2	+6	2,632.8	6,592
+5	1,977.5	91.0	+5	2,194.0	6,598
+4	1,582.0	90.8	+4	1,755.2	6,604
+3	1,186.5	90.6	+3	1,316.4	6,610
+2	791.0	90.4	+2	877.6	6,616
+1	395.5 <- Fuel Sav/(Loss) 593.3	90.2 <- Adj. Act. EAF= 90.3	+1	438.8	6,622
				0	6,628
0	0	90.0	0	0	6,703
				0	6,778
-1	(395.5)	89.8	-1	(438.8)	6,784
-2	(791.0)	89.6	-2	(877.6)	6,790
-3	(1,186.5)	89.4	-3	(1,316.4) <- Fuel Sav/(Loss) - 1,391.0	6,796 <- Adj. Act. HR=6,797
-4	(1,582.0)	89.2	-4	(1,755.2)	6,802
-5	(1,977.5)	89.0	-5	(2,194.0)	6,808
-6	(2,373.0)	88.8	-6	(2,632.8)	6,814
-7	(2,768.5)	88.6	-7	(3,071.6)	6,820
-8	(3,164.0)	88.4	-8	(3,510.4)	6,826
-9	(3,559.5)	88.2	-9	(3,949.2)	6,832
-10	(3,955.0)	88.0	-10	(4,388.0)	6,838
	WEIGHTING FACTOR =	3.41		WEIGHTING FACTOR =	3.78

ACTUAL PLANNED OUTAGES

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2015

PLANT/UNIT	ACTUAL PLANNED OUTAGE DATE	REASON FOR OUTAGE
Ft. Myers 2	11/14/15 - 11/30/15; 12/2/15 - 12/31/15	Steam Turbine 1 and 2 Ft. Myers site planned outage; CT-2A/HRSG outage
	5/29/15 - 8/9/15; 10/14/15 - 12/10/15	CT-2B .05 compresor upgrade and testing; CT-2C .05 compresor upgrade
	8/14/15 - 10/13/15; 8/2/15 - 10/4/15	CT-2D .05 compresor upgrade and testing; CT-2E .05 compresor upgrade;
	10/5/15 - 12/1/15; 12/3/15 - 12/4/15	CT-2F .05 compresor upgrade; CT-2F planned outage to remove test equipment
Martin 8	2/3/15 - 2/25/15; 1/8/15 - 2/24/15	CT-8A planned outage; CT-8B major outage
	2/3/15 - 2/22/15; 2/2/15 - 2/22/15	CT-8C planned outage; CT-8D and Steam Turbine planned outage
Manatee 3	6/18/15 - 6/24/15; 6/18/15 - 6/23/15	CT-3A & 3D planned outage; CT-3C planned outage
	6/18/15 - 6/24/15	Steam Turbine planned outage
St. Lucie 1	3/21/15 - 3/22/15; 3/22/15 - 4/27/15	Partial load reduction for Main Steam Safety Valve testing; Refueling outage
St. Lucie 2	3/9/15 - 3/13/15; 4/30/15	Partial load reduction for 2B2 (Unit 2 B 2nd) water box maint.; Partial load reduction for Moderator Temp Coef. test
	9/6/15 - 10/28/15	Partial load reduction for Main Steam Safety Valve (MSSV) testing & Refueling outage
Turkey Point 3	3/4/15 - 3/6/15; 4/29/15 - 5/5/15	Partial load reduction for Turbine Valve Testing (TVT); TVT and Normal Containment Cooler (NCC) repair
	8/16/15 - 8/19/15; 10/17/15 - 12/9/15	Partial load reduction for Moderator Temperature Coefficient (MTC) test; Refueling outage
Turkey Point 4	5/7/15 - 5/12/15 and 5/15/15	TVT and NCC repair
Turkey Point 5	NONE	
West County 1	12/6/15 - 12/14/15; 12/6/15 - 12/13/15	CT-1A controls upgrade; CT-1B planned block outage
	12/3/15 - 12/13/15; 12/6/15 - 12/13/15	CT-1C controls upgrade; Steam Turbine controls upgrade
West County 2	10/10/15 - 11/29/15; 10/13/15 - 12/3/15	CT-2A major overhaul; CT-2B major overhaul
	10/6/15 - 11/23/15; 10/7/15 - 11/24/15	CT-2C major overhaul; Steam Turbine (ST) outage
West County 3	9/10/15 - 9/22/15; 11/6/15 - 11/12/15	CT-3A Combustion Inspection (CI); CT-3A DCS upgrade
	9/23/15 - 10/5/15; 11/6/15 - 11/13/15	CT-3B planned outage; CT-3B DCS upgrade
	8/22/15 - 9/9/15; 11/6/15 - 11/12/15	CT-3C planned outage; CT-3C DCS upgrade
	11/6/15 - 11/12/15	Steam Turbine DCS upgrade

WITNESS: CHARLES R. ROTE

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2017

SEPTEMBER 2, 2016

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 35
PARTY: FLORIDA POWER & LIGHT COMPANY – (DIRECT & SUPPLEMENTAL)*Notice of Adoption of Terry J. Keith's testimony and exhibits by Renae B. Deaton, filed on October 3, 2016, (FPSC DN #07930-16).
DESCRIPTION: C. R. Rote CRR-2

CRR-2
DOCKET NO. 160001-EI
FPL Witness: Charles R. Rote
Exhibit No.: _____
Pages 1 - 34

EXHIBIT INDEX

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2017

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 Generation
January Through December, 2017

Name	Capacity (MW)	Service Hours	Net Output MWH	NOF %	% of Total Output	Cumulative % of Total Output	Production Cost ($000)
Port Everglades 5	1,225	8,760	8,754,725	81.6	7.5	7.5	259,598
Ft. Myers 2	1,470	8,760	8,751,829	68.0	7.5	15.1	292,522
St. Lucie 1	981	8,760	8,459,223	98.4	7.3	22.4	56,470
Riviera 5	1,216	8,760	8,410,942	79.0	7.2	29.6	252,481
West County 2	1,172	8,760	7,572,304	73.8	6.5	36.1	235,609
West County 1	1,182	8,269	7,149,638	73.1	6.2	42.3	223,630
Cape Canaveral 3	1,216	8,760	7,005,652	65.8	6.0	48.3	216,613
Turkey Point 4	821	8,040	6,531,218	98.9	5.6	54.0	44,134
St. Lucie 2	840	7,896	6,518,468	98.3	5.6	59.6	47,594
West County 3	1,182	8,088	6,516,374	68.2	5.6	65.2	200,965
Turkey Point 3	811	8,016	6,434,111	99.0	5.5	70.7	45,234
Martin 8	1,082	6,789	5,167,764	70.4	4.5	75.2	159,100
Manatee 3	1,087	5,790	4,745,864	75.4	4.1	79.3	151,433
Turkey Point 5	1,087	6,018	4,488,554	68.6	3.9	83.1	142,636
Scherer 4	625	8,760	4,337,573	79.2	3.7	86.9	106,900
Sanford 5	970	5,576	3,425,249	63.3	3.0	89.8	118,353
Sanford 4	970	5,173	2,978,551	59.4	2.6	92.4	105,313
Martin 3	451	4,617	1,550,755	74.5	1.3	93.7	55,038
Lauderdale 4	431	4,157	1,409,575	78.7	1.2	95.0	50,985
Lauderdale 5	431	4,237	1,391,658	76.2	1.2	96.2	50,793
Martin 4	431	3,964	1,191,500	69.7	1.0	97.2	43,257
St. Johns 2	127	8,568	637,811	58.6	0.5	97.7	24,301
St. Johns 1	127	7,896	601,380	60.0	0.5	98.2	22,978
Manatee 1	781	1,112	366,248	42.2	0.3	98.6	24,338
Manatee 2	781	946	313,502	42.4	0.3	98.8	20,531
Martin 1	796	999	303,997	38.2	0.3	99.1	20,712
Ft. Myers 4A	209	981	176,293	86.2	0.2	99.2	8,085
Ft. Myers 4B	209	877	155,770	85.2	0.1	99.4	7,188
Martin 2	768	437	154,533	46.0	0.1	99.5	10,906
Manatee PV Solar	75	4,049	102,580	34.0	0.1	99.6	0
Citrus PV Solar	75	4,049	102,580	34.0	0.1	99.7	0
Babcock PV Solar	75	4,049	102,580	34.0	0.1	99.8	0
Lauderdale 6 CT 2	208	552	101,142	88.0	0.1	99.9	4,859
Desoto	25	4,168	52,307	50.2	0.0	99.9	0
Ft. Myers 3A	171	204	23,811	68.5	0.0	99.9	1,312
Ft. Myers 3B	171	180	20,772	67.7	0.0	100.0	1,151
Space Coast	10	3,895	17,803	45.7	0.0	100.0	0
Lauderdale 6 CT 1	208	111	17,373	75.2	0.0	100.0	903
Lauderdale 6 CT 3	208	74	11,100	72.0	0.0	100.0	1,978
Lauderdale 6 CT 4	208	52	7,800	72.0	0.0	100.0	1,385
Lauderdale 6 CT 5	208	20	3,000	72.0	0.0	100.0	524
Total	**25,119**		**116,063,909**		**100.0**		**3,009,808**

UNITS TO BE USED TO DETERMINE THE GENERATING PERFORMANCE INCENTIVE FACTOR

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2017

Cape Canaveral 3

Ft. Myers 2

Manatee 3

Martin 8

St. Lucie 1

St. Lucie 2

Turkey Point 3

Turkey Point 4

Turkey Point 5

West County 1

West County 2

West County 3

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2017

Generating Performance Incentive Points (GPIF)	Fuel Savings/(Loss) ($000)	Generating Performance Incentive Factor ($000)
+ 10	61,121	30,561
+ 9	55,009	27,504
+ 8	48,897	24,448
+ 7	42,785	21,392
+ 6	36,673	18,336
+ 5	30,561	15,280
+ 4	24,448	12,224
+ 3	18,336	9,168
+ 2	12,224	6,112
+ 1	6,112	3,056
0	0	0
- 1	(6,112)	(3,056)
- 2	(12,224)	(6,112)
- 3	(18,336)	(9,168)
- 4	(24,448)	(12,224)
- 5	(30,561)	(15,280)
- 6	(36,673)	(18,336)
- 7	(42,785)	(21,392)
- 8	(48,897)	(24,448)
- 9	(55,009)	(27,504)
- 10	(61,121)	(30,561)

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2017

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$	16,091,437,844	
LINE 2	MONTH OF JANUARY	2016	$	16,201,281,085	
LINE 3	MONTH OF FEBRUARY	2016	$	16,299,650,216	
LINE 4	MONTH OF MARCH	2016	$	16,165,306,692	
LINE 5	MONTH OF APRIL	2016	$	16,293,106,710	
LINE 6	MONTH OF MAY	2016	$	16,464,566,486	
LINE 7	MONTH OF JUNE	2016	$	16,657,388,072	
LINE 8	MONTH OF JULY	2016	$	16,374,574,592	
LINE 9	MONTH OF AUGUST	2016	$	16,599,131,215	
LINE 10	MONTH OF SEPTEMBER	2016	$	16,794,358,695	
LINE 11	MONTH OF OCTOBER	2016	$	16,962,345,501	
LINE 12	MONTH OF NOVEMBER	2016	$	17,073,976,934	
LINE 13	MONTH OF DECEMBER	2016	$	17,202,582,094	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE 1 THROUGH LINE 13 DIVIDED BY 13)		$	16,552,285,087	
LINE 15	25 BASIS POINTS			0.0025	
LINE 16	REVENUE EXPANSION FACTOR			61.3808%	
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$	67,416,379	
LINE 18	JURISDICTIONAL SALES			107,335,993,752	KWH
LINE 19	TOTAL SALES			113,323,505,930	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)			94.72%	
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)		$	63,856,794	
LINE 22	INCENTIVE CAP (50 PECENT OF PROJECTED FUEL SAVINGS AT 10 GPIF·POINT LEVEL FROM SHEET NO. 3.515)		$	30,560,500	
LINE 23	MAXIMUM ALLOWED GPIF REWARD (AT 10 GPIF-POINT LEVEL) (THE LESSER OF LINE 21 AND LINE 22)		$	30,560,500	

Note: Line 22 and 23 are as approved by Commission order PSC-13-0665-FOF-EI dated 12/18/13 effective 1/1/14.

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2017

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	1.91	79.4	82.4	76.4	1,168	-1,168
Manatee 3	0.80	70.9	72.9	68.9	486	-486
Ft. Myers 2	1.65	92.4	94.9	89.9	1,011	-1,011
Martin 8	1.06	72.9	75.4	70.4	645	-645
St. Lucie 1	9.14	93.6	96.6	90.6	5,588	-5,588
St. Lucie 2	6.77	83.7	86.7	80.7	4,137	-4,137
Turkey Point 3	6.80	85.1	88.1	82.1	4,156	-4,156
Turkey Point 4	7.12	85.4	88.4	82.4	4,351	-4,351
Turkey Point 5	0.99	78.3	80.3	76.3	608	-608
West County 1	1.46	89.5	92.0	87.0	891	-891
West County 2	1.53	93.0	95.5	90.5	938	-938
West County 3	1.48	76.1	78.6	73.6	905	-905
	40.71				24,884	-24,884

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2017

Plant / Unit	Weighting Factor (%)	ANOHR TARGET BTU/KWH	ANOHR TARGET NOF	ANOHR RANGE BTU/KWH	ANOHR RANGE BTU/KWH	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Cape Canaveral 3	4.31	6,663	65.8	6,582	6,744	2,633	-2,633
Manatee 3	6.40	6,968	75.4	6,788	7,148	3,912	-3,912
Ft. Myers 2	13.83	7,301	68.0	7,090	7,512	8,454	-8,454
Martin 8	4.22	6,977	70.4	6,864	7,090	2,577	-2,577
St. Lucie 1	0.94	10,401	98.4	10,293	10,509	576	-576
St. Lucie 2	0.70	10,278	98.3	10,184	10,372	427	-427
Turkey Point 3	1.19	11,106	99.0	10,926	11,286	730	-730
Turkey Point 4	0.97	11,019	98.9	10,870	11,168	590	-590
Turkey Point 5	2.68	7,134	68.6	7,052	7,216	1,639	-1,639
West County 1	9.74	6,989	73.1	6,803	7,175	5,952	-5,952
West County 2	7.66	6,941	73.8	6,803	7,079	4,684	-4,684
West County 3	6.65	6,975	68.2	6,834	7,116	4,063	-4,063
	59.29					36,237	-36,237

GENERATING PERFORMANCE INCENTIVE FACTOR
PROJECTED UNIT HEAT RATE EQUATIONS
FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2017

				ANOHR Equation					
Plant/Unit	ANOHR	NOF	MW	a coef.	b coef.	Bounds	First	Last	Exclusions
Cape Canaveral 3	6,663	65.8	1216	6843	-2.73	81	07-13	06-16	9/13, 12/13, 2/14, 3/14, 8/14, 5/16
Manatee 3	6,968	75.4	1087	7594	-8.30	180	07-13	06-16	6/14, 6/15, 11/15
Ft. Myers 2	7,301	68.0	1470	7634	-4.89	211	07-13	06-16	9/13, 10/13, 11/13
Martin 8	6,977	70.4	1082	7148	-2.43	113	07-13	06-16	2/15, 2/16
St. Lucie 1	10,401	98.4	981	12922	-25.62	108	07-13	06-16	10/13, 4/15
St. Lucie 2	10,278	98.3	840	12471	-22.31	94	07-13	06-16	10/15
Turkey Point 3	11,106	99.0	811	15143	-40.78	180	07-13	06-16	4/14, 9/14, 11/15, 12/15
Turkey Point 4	11,019	98.9	821	17890	-69.47	149	07-13	06-16	10/14, 4/16
Turkey Point 5	7,134	68.6	1087	7749	-8.97	82	07-13	06-16	2/14, 11/14
West County 1	6,989	73.1	1182	7903	-12.51	186	07-13	06-16	12/13, 10/14, 11/14
West County 2	6,941	73.8	1172	7620	-9.20	138	07-13	06-16	12/13, 1/14, 12/14, 10/15, 11/15
West County 3	6,975	68.2	1182	7227	-3.70	141	07-13	06-16	7/13, 12/13, 1/14, 12/14, 5/16

DERIVATION OF WEIGHTING FACTORS

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2017

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	3,009,808	3,008,640	1,168	1.91
Cape Canaveral 3	ANOHR	3,009,808	3,007,175	2,633	4.31
Manatee 3	EAF	3,009,808	3,009,322	486	0.80
Manatee 3	ANOHR	3,009,808	3,005,896	3,912	6.40
Ft. Myers 2	EAF	3,009,808	3,008,797	1,011	1.65
Ft. Myers 2	ANOHR	3,009,808	3,001,354	8,454	13.83
Martin 8	EAF	3,009,808	3,009,163	645	1.06
Martin 8	ANOHR	3,009,808	3,007,231	2,577	4.22
St. Lucie 1	EAF	3,009,808	3,004,220	5,588	9.14
St. Lucie 1	ANOHR	3,009,808	3,009,232	576	0.94
St. Lucie 2	EAF	3,009,808	3,005,671	4,137	6.77
St. Lucie 2	ANOHR	3,009,808	3,009,381	427	0.70
Turkey Point 3	EAF	3,009,808	3,005,652	4,156	6.80
Turkey Point 3	ANOHR	3,009,808	3,009,078	730	1.19
Turkey Point 4	EAF	3,009,808	3,005,457	4,351	7.12
Turkey Point 4	ANOHR	3,009,808	3,009,218	590	0.97
Turkey Point 5	EAF	3,009,808	3,009,200	608	0.99
Turkey Point 5	ANOHR	3,009,808	3,008,169	1,639	2.68
West County 1	EAF	3,009,808	3,008,917	891	1.46
West County 1	ANOHR	3,009,808	3,003,856	5,952	9.74
West County 2	EAF	3,009,808	3,008,870	938	1.53
West County 2	ANOHR	3,009,808	3,005,124	4,684	7.66
West County 3	EAF	3,009,808	3,008,903	905	1.48
West County 3	ANOHR	3,009,808	3,005,745	4,063	6.65
	TOTAL			61,121	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, 2017

	Cape Canaveral 3	Jan '17	Feb '17	Mar '17	Apr '17	May '17	Jun '17
1	EAF (%)	88.3	73.6	59.8	58.9	88.3	88.3
2	EPOF (%)	0.0	16.7	32.3	33.3	0.0	0.0
3	EUOF (%)	11.7	9.7	7.9	7.8	11.7	11.7
4	EUOR (%)	11.7	9.7	7.9	7.8	11.7	11.7
5	PH	744	672	744	720	744	720
6	SH	744	672	744	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	17	12	11	11	17	16
11	MOH & EMOH	70	53	48	45	70	68
12	Oper Mbtu	5,480,325	3,557,810	2,916,512	3,144,891	4,509,173	4,676,567
13	Net Gen (MWH)	831,360	533,805	434,522	469,597	679,297	706,110
14	ANOHR (Btu/KWH)	6,592	6,665	6,712	6,697	6,638	6,623
15	NOF (%)	91.9	65.3	48.0	53.6	75.1	80.7
16	NSC (MW)	1,216	1,216	1,216	1,216	1,216	1,216
17	ANOHR Equation	-2.73 x NOF + 6843					

	Cape Canaveral 3	Jul '17	Aug '17	Sep '17	Oct '17	Nov '17	Dec '17	Total
1	EAF (%)	88.3	88.3	88.3	88.3	70.7	70.3	79.4
2	EPOF (%)	0.0	0.0	0.0	0.0	20.0	20.4	10.1
3	EUOF (%)	11.7	11.7	11.7	11.7	9.3	9.3	10.5
4	EUOR (%)	11.7	11.7	11.7	11.7	9.3	9.3	10.5
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	8,760
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	0
9	POH	0	0	0	0	0	0	0
10	FOH & EFOH	17	17	16	17	13	13	175
11	MOH & EMOH	70	70	68	70	54	56	745
12	Oper Mbtu	3,846,526	4,217,195	3,662,154	3,851,261	3,159,836	3,619,617	46,678,659
13	Net Gen (MWH)	576,777	633,974	548,884	577,487	471,899	541,940	7,005,652
14	ANOHR (Btu/KWH)	6,669	6,652	6,672	6,669	6,696	6,679	6,663
15	NOF (%)	63.8	70.1	62.7	63.8	53.9	59.9	65.8
16	NSC (MW)	1,216	1,216	1,216	1,216	1,216	1,216	1,216
17	ANOHR Equation	-2.73 x NOF + 6843						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2017

	Ft. Myers 2	Jan '17	Feb '17	Mar '17	Apr '17	May '17	Jun '17
1	EAF (%)	94.8	94.8	94.8	94.8	94.8	94.8
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	5.2	5.2	5.2	5.2	5.2	5.2
4	EUOR (%)	5.2	5.2	5.2	5.2	5.2	5.2
5	PH	744	672	744	720	744	720
6	SH	744	672	744	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	15	14	15	15	15	15
11	MOH & EMOH	24	21	24	23	24	23
12	Oper Mbtu	4,446,906	4,528,924	5,550,668	5,576,254	5,911,986	4,960,446
13	Net Gen (MWH)	603,871	618,030	760,991	765,969	813,203	677,564
14	ANOHR (Btu/KWH)	7,364	7,328	7,294	7,280	7,270	7,321
15	NOF (%)	55.2	62.6	69.6	72.4	74.4	64.0
16	NSC (MW)	1,470	1,470	1,470	1,470	1,470	1,470
17	ANOHR Equation	-4.89 x NOF + 7634					

	Ft. Myers 2	Jul '17	Aug '17	Sep '17	Oct '17	Nov '17	Dec '17	Total
1	EAF (%)	94.8	94.8	94.8	94.8	81.6	80.1	92.4
2	EPOF (%)	0.0	0.0	0.0	0.0	13.9	15.5	2.5
3	EUOF (%)	5.2	5.2	5.2	5.2	4.5	4.4	5.1
4	EUOR (%)	5.2	5.2	5.2	5.2	4.5	4.4	5.1
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	8,760
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	0
9	POH	0	0	0	0	0	0	0
10	FOH & EFOH	15	15	15	15	13	13	175
11	MOH & EMOH	24	24	23	24	20	20	272
12	Oper Mbtu	5,292,835	5,227,160	5,251,310	6,297,187	5,355,362	5,480,915	63,897,104
13	Net Gen (MWH)	724,054	714,581	719,259	869,177	734,114	751,016	8,751,829
14	ANOHR (Btu/KWH)	7,310	7,315	7,301	7,245	7,295	7,298	7,301
15	NOF (%)	66.2	65.3	68.0	79.5	69.4	68.7	68.0
16	NSC (MW)	1,470	1,470	1,470	1,470	1,470	1,470	1,470
17	ANOHR Equation	-4.89 x NOF + 7634						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2017

	Manatee 3	Jan '17	Feb '17	Mar '17	Apr '17	May '17	Jun '17
1	EAF (%)	94.4	94.4	51.7	0.0	0.0	59.0
2	EPOF (%)	0.0	0.0	45.2	100.0	100.0	37.5
3	EUOF (%)	5.6	5.6	3.1	0.0	0.0	3.5
4	EUOR (%)	7.7	8.9	6.3	0.0	0.0	4.2
5	PH	744	672	744	720	744	720
6	SH	543	424	361	0	0	600
7	RSH	201	248	215	0	0	0
8	UH	0	0	168	720	744	120
9	POH	0	0	168	720	744	120
10	FOH & EFOH	20	18	11	0	0	12
11	MOH & EMOH	22	20	12	0	0	13
12	Oper Mbtu	3,002,666	2,626,588	1,795,350	0	0	2,937,373
13	Net Gen (MWH)	429,566	380,169	254,443	0	0	415,764
14	ANOHR (Btu/KWH)	6,990	6,909	7,056	0	0	7,065
15	NOF (%)	72.8	82.5	64.8	0.0	0.0	63.7
16	NSC (MW)	1,087	1,087	1,087	1,087	1,087	1,087
17	ANOHR Equation	-8.3 x NOF + 7594					

	Manatee 3	Jul '17	Aug '17	Sep '17	Oct '17	Nov '17	Dec '17	Total
1	EAF (%)	80.7	94.4	94.4	94.4	94.4	94.4	70.9
2	EPOF (%)	14.5	0.0	0.0	0.0	0.0	0.0	24.9
3	EUOF (%)	4.8	5.6	5.6	5.6	5.6	5.6	4.2
4	EUOR (%)	4.8	5.6	5.6	5.9	6.5	12.4	6.4
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	701	618	335	5,790
7	RSH	0	0	0	43	102	409	1218
8	UH	0	0	0	0	0	0	1,752
9	POH	0	0	0	0	0	0	1,752
10	FOH & EFOH	17	20	19	20	19	20	175
11	MOH & EMOH	19	22	21	22	21	22	193
12	Oper Mbtu	3,713,085	4,038,193	3,962,528	4,771,957	3,962,578	2,210,025	33,069,180
13	Net Gen (MWH)	526,380	576,720	566,642	698,267	575,705	322,208	4,745,864
14	ANOHR (Btu/KWH)	7,054	7,002	6,993	6,834	6,883	6,859	6,968
15	NOF (%)	65.1	71.3	72.4	91.6	85.7	88.5	75.4
16	NSC (MW)	1,087	1,087	1,087	1,087	1,087	1,087	1,087
17	ANOHR Equation	-8.3 x NOF + 7594						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2017

	Martin 8	Jan '17	Feb '17	Mar '17	Apr '17	May '17	Jun '17
1	EAF (%)	13.5	0.0	21.0	92.9	92.9	92.9
2	EPOF (%)	85.5	100.0	77.4	0.0	0.0	0.0
3	EUOF (%)	1.0	0.0	1.6	7.1	7.1	7.1
4	EUOR (%)	5.4	0.0	7.1	7.1	7.1	7.1
5	PH	744	672	744	720	744	720
6	SH	144	0	168	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	600	672	576	0	0	0
9	POH	600	672	576	0	0	0
10	FOH & EFOH	3	0	4	18	19	18
11	MOH & EMOH	5	0	8	33	34	33
12	Oper Mbtu	510,438	0	885,738	3,680,209	4,438,292	3,938,016
13	Net Gen (MWH)	72,557	0	126,933	527,024	638,144	564,833
14	ANOHR (Btu/KWH)	7,035	0	6,978	6,983	6,955	6,972
15	NOF (%)	46.6	0.0	69.8	67.7	79.3	72.5
16	NSC (MW)	1,082	1,082	1,082	1,082	1,082	1,082
17	ANOHR Equation	-2.43 x NOF + 7148					

	Martin 8	Jul '17	Aug '17	Sep '17	Oct '17	Nov '17	Dec '17	Total
1	EAF (%)	92.9	92.9	92.9	92.9	92.9	92.9	72.9
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	21.5
3	EUOF (%)	7.1	7.1	7.1	7.1	7.1	7.1	5.6
4	EUOR (%)	7.1	7.1	7.1	7.1	8.6	7.1	7.2
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	597	744	6,789
7	RSH	0	0	0	0	123	0	123
8	UH	0	0	0	0	0	0	1,848
9	POH	0	0	0	0	0	0	1,848
10	FOH & EFOH	19	19	18	19	18	19	175
11	MOH & EMOH	34	34	33	34	33	34	315
12	Oper Mbtu	3,775,001	3,673,733	3,558,827	4,075,392	3,813,212	3,697,127	36,055,489
13	Net Gen (MWH)	540,444	525,645	509,204	584,537	549,375	529,068	5,167,764
14	ANOHR (Btu/KWH)	6,985	6,989	6,989	6,972	6,941	6,988	6,977
15	NOF (%)	67.1	65.3	65.4	72.6	85.0	65.7	70.4
16	NSC (MW)	1,082	1,082	1,082	1,082	1,082	1,082	1,082
17	ANOHR Equation	-2.43 x NOF + 7148						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2017

	St. Lucie 1	Jan '17	Feb '17	Mar '17	Apr '17	May '17	Jun '17
1	EAF (%)	93.6	93.6	93.6	93.6	93.6	93.6
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	6.4	6.4	6.4	6.4	6.4	6.4
4	EUOR (%)	6.4	6.4	6.4	6.4	6.4	6.4
5	PH	744	672	744	720	744	720
6	SH	744	672	744	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	24	22	24	23	24	23
11	MOH & EMOH	24	22	24	23	24	23
12	Oper Mbtu	7,546,535	6,816,218	7,546,535	7,179,079	7,418,385	7,179,079
13	Net Gen (MWH)	728,079	657,619	728,079	688,707	711,664	688,707
14	ANOHR (Btu/KWH)	10,365	10,365	10,365	10,424	10,424	10,424
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	-25.62 x NOF + 12922					

	St. Lucie 1	Jul '17	Aug '17	Sep '17	Oct '17	Nov '17	Dec '17	Total
1	EAF (%)	93.6	93.6	93.6	93.6	93.6	93.6	93.6
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	6.4	6.4	6.4	6.4	6.4	6.4	6.4
4	EUOR (%)	6.4	6.4	6.4	6.4	6.4	6.4	6.4
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	8,760
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	0
9	POH	0	0	0	0	0	0	0
10	FOH & EFOH	24	24	23	24	23	24	280
11	MOH & EMOH	24	24	23	24	23	24	280
12	Oper Mbtu	7,418,385	7,418,385	7,179,079	7,418,385	7,303,100	7,546,535	87,984,378
13	Net Gen (MWH)	711,664	711,664	688,707	711,664	704,592	728,079	8,459,223
14	ANOHR (Btu/KWH)	10,424	10,424	10,424	10,424	10,365	10,365	10,401
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	-25.62 x NOF + 12922						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2017

	St. Lucie 2	Jan '17	Feb '17	Mar '17	Apr '17	May '17	Jun '17
1	EAF (%)	92.9	63.1	12.0	92.9	92.9	92.9
2	EPOF (%)	0.0	32.1	87.1	0.0	0.0	0.0
3	EUOF (%)	7.1	4.8	0.9	7.1	7.1	7.1
4	EUOR (%)	7.1	7.1	7.1	7.1	7.1	7.1
5	PH	744	672	744	720	744	720
6	SH	744	456	96	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	216	648	0	0	0
9	POH	0	216	648	0	0	0
10	FOH & EFOH	26	16	3	26	26	26
11	MOH & EMOH	26	16	3	26	26	26
12	Oper Mbtu	6,387,400	3,914,854	824,176	6,070,885	6,273,250	6,070,885
13	Net Gen (MWH)	623,343	382,049	80,431	589,635	609,290	589,635
14	ANOHR (Btu/KWH)	10,247	10,247	10,247	10,296	10,296	10,296
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	-22.31 x NOF + 12471					

	St. Lucie 2	Jul '17	Aug '17	Sep '17	Oct '17	Nov '17	Dec '17	Total
1	EAF (%)	92.9	92.9	92.9	92.9	92.9	92.9	83.7
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	9.9
3	EUOF (%)	7.1	7.1	7.1	7.1	7.1	7.1	6.4
4	EUOR (%)	7.1	7.1	7.1	7.1	7.1	7.1	7.1
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	7,896
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	864
9	POH	0	0	0	0	0	0	864
10	FOH & EFOH	26	26	26	26	26	26	280
11	MOH & EMOH	26	26	26	26	26	26	280
12	Oper Mbtu	6,273,250	6,273,250	6,070,885	6,273,250	6,181,356	6,387,400	66,996,814
13	Net Gen (MWH)	609,290	609,290	589,635	609,290	603,236	623,343	6,518,468
14	ANOHR (Btu/KWH)	10,296	10,296	10,296	10,296	10,247	10,247	10,278
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	-22.31 x NOF + 12471						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2017

	Turkey Point 3	Jan '17	Feb '17	Mar '17	Apr '17	May '17	Jun '17
1	EAF (%)	93.0	93.0	78.0	12.4	93.0	93.0
2	EPOF (%)	0.0	0.0	16.1	86.7	0.0	0.0
3	EUOF (%)	7.0	7.0	5.9	0.9	7.0	7.0
4	EUOR (%)	7.0	7.0	7.0	7.0	7.0	7.0
5	PH	744	672	744	720	744	720
6	SH	744	672	624	96	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	120	624	0	0
9	POH	0	0	120	624	0	0
10	FOH & EFOH	26	23	22	3	26	25
11	MOH & EMOH	26	23	22	3	26	25
12	Oper Mbtu	6,711,762	6,062,235	5,629,221	847,687	6,569,535	6,357,619
13	Net Gen (MWH)	608,611	549,713	510,448	75,910	588,299	569,322
14	ANOHR (Btu/KWH)	11,028	11,028	11,028	11,167	11,167	11,167
15	NOF (%)	100.9	100.9	100.9	97.5	97.5	97.5
16	NSC (MW)	811	811	811	811	811	811
17	ANOHR Equation	-40.78 x NOF + 15143					

	Turkey Point 3	Jul '17	Aug '17	Sep '17	Oct '17	Nov '17	Dec '17	Total
1	EAF (%)	93.0	93.0	93.0	93.0	93.0	93.0	85.1
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	8.5
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	7.0
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	8,016
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	744
9	POH	0	0	0	0	0	0	744
10	FOH & EFOH	26	26	25	26	25	26	280
11	MOH & EMOH	26	26	25	26	25	26	280
12	Oper Mbtu	6,569,535	6,569,535	6,357,619	6,569,535	6,495,249	6,711,762	71,457,237
13	Net Gen (MWH)	588,299	588,299	569,322	588,299	588,978	608,611	6,434,111
14	ANOHR (Btu/KWH)	11,167	11,167	11,167	11,167	11,028	11,028	11,106
15	NOF (%)	97.5	97.5	97.5	97.5	100.9	100.9	99.0
16	NSC (MW)	811	811	811	811	811	811	811
17	ANOHR Equation	-40.78 x NOF + 15143						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2017

	Turkey Point 4	Jan '17	Feb '17	Mar '17	Apr '17	May '17	Jun '17
1	EAF (%)	93.0	93.0	93.0	93.0	93.0	93.0
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	7.0	7.0	7.0	7.0	7.0	7.0
4	EUOR (%)	7.0	7.0	7.0	7.0	7.0	7.0
5	PH	744	672	744	720	744	720
6	SH	744	672	744	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	26	23	26	25	26	25
11	MOH & EMOH	26	23	26	25	26	25
12	Oper Mbtu	6,701,324	6,052,804	6,701,324	6,407,194	6,620,763	6,407,194
13	Net Gen (MWH)	615,139	555,609	615,139	576,342	595,553	576,342
14	ANOHR (Btu/KWH)	10,894	10,894	10,894	11,117	11,117	11,117
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	-69.47 x NOF + 17890					

	Turkey Point 4	Jul '17	Aug '17	Sep '17	Oct '17	Nov '17	Dec '17	Total
1	EAF (%)	93.0	93.0	93.0	3.0	93.0	93.0	85.4
2	EPOF (%)	0.0	0.0	0.0	96.8	0.0	0.0	8.2
3	EUOF (%)	7.0	7.0	7.0	0.2	7.0	7.0	6.4
4	EUOR (%)	7.0	7.0	7.0	7.0	7.0	7.0	7.0
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	24	720	744	8,040
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	720	0	0	720
9	POH	0	0	0	720	0	0	720
10	FOH & EFOH	26	26	25	1	25	26	280
11	MOH & EMOH	26	26	25	1	25	26	280
12	Oper Mbtu	6,620,763	6,620,763	6,407,194	213,569	6,485,155	6,701,324	71,967,491
13	Net Gen (MWH)	595,553	595,553	576,342	19,211	595,296	615,139	6,531,218
14	ANOHR (Btu/KWH)	11,117	11,117	11,117	11,117	10,894	10,894	11,019
15	NOF (%)	97.5	97.5	97.5	97.5	100.7	100.7	98.9
16	NSC (MW)	821	821	821	821	821	821	821
17	ANOHR Equation	-69.47 x NOF + 17890						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2017

	Turkey Point 5	Jan '17	Feb '17	Mar '17	Apr '17	May '17	Jun '17
1	EAF (%)	95.1	95.1	95.1	95.1	95.1	95.1
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	4.9	4.9	4.9	4.9	4.9	4.9
4	EUOR (%)	9.1	6.5	7.5	5.8	7.4	4.9
5	PH	744	672	744	720	744	720
6	SH	397	505	480	608	490	720
7	RSH	347	167	264	112	254	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	18	16	18	18	18	18
11	MOH & EMOH	18	16	18	18	18	18
12	Oper Mbtu	1,912,078	2,930,382	3,059,165	4,058,011	2,960,989	3,800,775
13	Net Gen (MWH)	265,714	414,364	437,211	583,299	420,595	532,396
14	ANOHR (Btu/KWH)	7,196	7,072	6,997	6,957	7,040	7,139
15	NOF (%)	61.6	75.5	83.8	88.3	79.0	68.0
16	NSC (MW)	1,087	1,087	1,087	1,087	1,087	1,087
17	ANOHR Equation	-8.97 x NOF + 7749					

	Turkey Point 5	Jul '17	Aug '17	Sep '17	Oct '17	Nov '17	Dec '17	Total
1	EAF (%)	95.1	95.1	71.4	41.4	14.3	51.4	78.3
2	EPOF (%)	0.0	0.0	25.0	56.5	85.0	46.0	17.7
3	EUOF (%)	4.9	4.9	3.6	2.1	0.7	2.6	4
4	EUOR (%)	4.9	4.9	3.6	4.7	4.3	12.7	5.8
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	334	122	154	6,018
7	RSH	0	0	0	410	358	590	2502
8	UH	0	0	0	0	240	0	240
9	POH	0	0	0	0	240	0	240
10	FOH & EFOH	18	18	13	8	3	10	175
11	MOH & EMOH	18	18	13	8	3	10	175
12	Oper Mbtu	3,822,792	3,929,169	3,246,764	1,234,569	429,099	549,954	32,021,344
13	Net Gen (MWH)	534,208	550,458	448,758	168,358	58,349	74,844	4,488,554
14	ANOHR (Btu/KWH)	7,156	7,138	7,235	7,333	7,354	7,348	7,134
15	NOF (%)	66.1	68.1	57.3	46.4	44.0	44.7	68.6
16	NSC (MW)	1,087	1,087	1,087	1,087	1,087	1,087	1,087
17	ANOHR Equation	-8.97 x NOF + 7749						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2017

	West County 1	Jan '17	Feb '17	Mar '17	Apr '17	May '17	Jun '17
1	EAF (%)	92.0	78.8	74.1	92.0	92.0	92.0
2	EPOF (%)	0.0	14.3	19.4	0.0	0.0	0.0
3	EUOF (%)	8.0	6.9	6.5	8.0	8.0	8.0
4	EUOR (%)	8.0	8.0	8.0	8.0	8.0	8.0
5	PH	744	672	744	720	744	720
6	SH	744	576	600	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	96	144	0	0	0
9	POH	0	96	144	0	0	0
10	FOH & EFOH	15	12	12	15	15	15
11	MOH & EMOH	44	34	36	43	44	43
12	Oper Mbtu	4,563,028	3,462,897	4,088,340	4,910,598	4,447,871	4,062,443
13	Net Gen (MWH)	654,479	495,124	596,838	717,085	635,501	575,743
14	ANOHR (Btu/KWH)	6,972	6,994	6,850	6,848	6,999	7,056
15	NOF (%)	74.4	72.7	84.2	84.3	72.3	67.7
16	NSC (MW)	1,182	1,182	1,182	1,182	1,182	1,182
17	ANOHR Equation	-12.51 x NOF + 7903					

	West County 1	Jul '17	Aug '17	Sep '17	Oct '17	Nov '17	Dec '17	Total
1	EAF (%)	92.0	92.0	92.0	92.0	92.0	92.0	89.5
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	2.7
3	EUOF (%)	8.0	8.0	8.0	8.0	8.0	8.0	7.8
4	EUOR (%)	8.0	8.0	8.0	8.0	12.3	8.0	8.3
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	469	744	8,269
7	RSH	0	0	0	0	251	0	251
8	UH	0	0	0	0	0	0	240
9	POH	0	0	0	0	0	0	240
10	FOH & EFOH	15	15	15	15	15	15	175
11	MOH & EMOH	44	44	43	44	43	44	508
12	Oper Mbtu	4,259,734	4,215,530	4,004,349	4,078,060	3,009,291	4,807,197	49,968,820
13	Net Gen (MWH)	604,904	597,778	566,386	575,672	434,743	695,385	7,149,638
14	ANOHR (Btu/KWH)	7,042	7,052	7,070	7,084	6,922	6,913	6,989
15	NOF (%)	68.8	68.0	66.6	65.5	78.4	79.1	73.1
16	NSC (MW)	1,182	1,182	1,182	1,182	1,182	1,182	1,182
17	ANOHR Equation	-12.51 x NOF + 7903						

ESTIMATED UNIT PERFORMANCE DATA

FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2017

	West County 2	Jan '17	Feb '17	Mar '17	Apr '17	May '17	Jun '17
1	EAF (%)	93.0	93.0	93.0	93.0	93.0	93.0
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	7.0	7.0	7.0	7.0	7.0	7.0
4	EUOR (%)	7.0	7.0	7.0	7.0	7.0	7.0
5	PH	744	672	744	720	744	720
6	SH	744	672	744	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	15	13	15	14	15	14
11	MOH & EMOH	37	34	37	36	37	36
12	Oper Mbtu	4,683,190	4,525,514	5,296,770	4,964,977	4,293,004	3,887,580
13	Net Gen (MWH)	678,330	660,852	779,166	727,256	615,926	554,102
14	ANOHR (Btu/KWH)	6,904	6,848	6,798	6,827	6,970	7,016
15	NOF (%)	77.8	83.9	89.4	86.2	70.6	65.7
16	NSC (MW)	1,172	1,172	1,172	1,172	1,172	1,172
17	ANOHR Equation	-9.2 x NOF + 7620					

	West County 2	Jul '17	Aug '17	Sep '17	Oct '17	Nov '17	Dec '17	Total
1	EAF (%)	93.0	93.0	93.0	93.0	93.0	93.0	93.0
2	EPOF (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	EUOF (%)	7.0	7.0	7.0	7.0	7.0	7.0	7
4	EUOR (%)	7.0	7.0	7.0	7.0	7.0	7.0	7.0
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	720	744	8,760
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	0	0	0
9	POH	0	0	0	0	0	0	0
10	FOH & EFOH	15	15	14	15	14	15	175
11	MOH & EMOH	37	37	36	37	36	37	438
12	Oper Mbtu	4,099,192	4,052,586	3,859,296	4,028,098	3,976,932	4,824,146	52,559,362
13	Net Gen (MWH)	585,348	578,115	549,679	574,294	568,052	701,184	7,572,304
14	ANOHR (Btu/KWH)	7,003	7,010	7,021	7,014	7,001	6,880	6,941
15	NOF (%)	67.1	66.3	65.1	65.9	67.3	80.4	73.8
16	NSC (MW)	1,172	1,172	1,172	1,172	1,172	1,172	1,172
17	ANOHR Equation	-9.2 x NOF + 7620						

ESTIMATED UNIT PERFORMANCE DATA

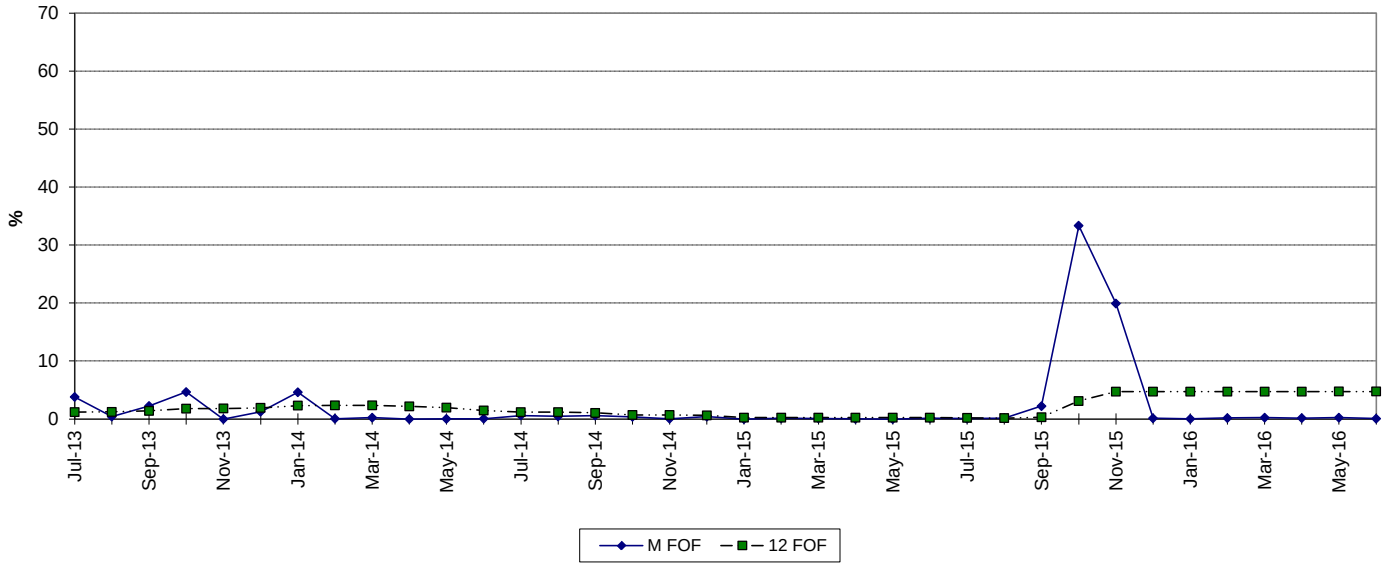
FLORIDA POWER & LIGHT

PERIOD OF: JANUARY THROUGH DECEMBER, 2017

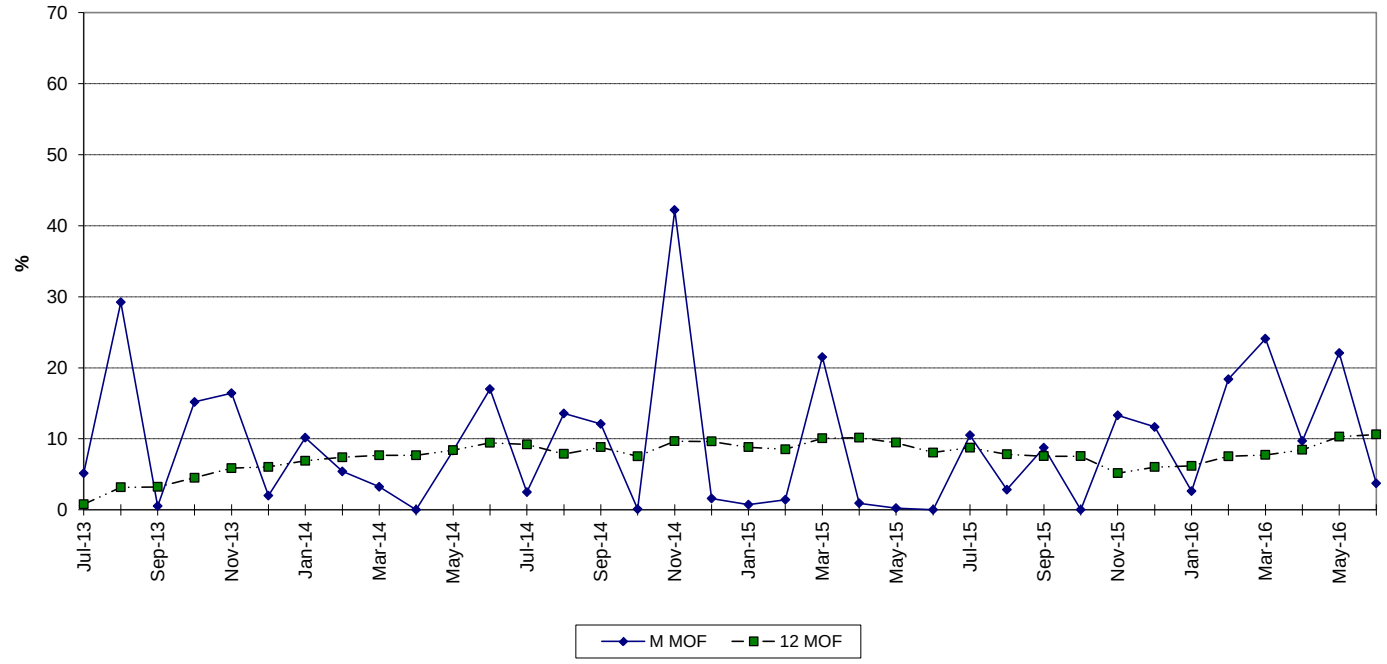
	West County 3	Jan '17	Feb '17	Mar '17	Apr '17	May '17	Jun '17
1	EAF (%)	91.8	91.8	91.8	68.3	62.1	91.8
2	EPOF (%)	0.0	0.0	0.0	25.6	32.3	0.0
3	EUOF (%)	8.2	8.2	8.2	6.1	5.6	8.2
4	EUOR (%)	8.2	8.2	8.2	6.1	5.6	8.2
5	PH	744	672	744	720	744	720
6	SH	744	672	744	720	744	720
7	RSH	0	0	0	0	0	0
8	UH	0	0	0	0	0	0
9	POH	0	0	0	0	0	0
10	FOH & EFOH	18	16	18	13	12	17
11	MOH & EMOH	43	39	43	31	29	42
12	Oper Mbtu	4,435,868	4,158,573	5,553,519	3,622,373	2,994,153	4,334,144
13	Net Gen (MWH)	637,429	598,528	806,260	517,334	424,823	623,080
14	ANOHR (Btu/KWH)	6,959	6,948	6,888	7,002	7,048	6,956
15	NOF (%)	72.5	75.4	91.7	60.8	48.3	73.2
16	NSC (MW)	1,182	1,182	1,182	1,182	1,182	1,182
17	ANOHR Equation	-3.7 x NOF + 7227					

	West County 3	Jul '17	Aug '17	Sep '17	Oct '17	Nov '17	Dec '17	Total
1	EAF (%)	91.8	91.8	91.8	77.9	2.0	60.2	76.1
2	EPOF (%)	0.0	0.0	0.0	15.1	97.8	34.4	17.1
3	EUOF (%)	8.2	8.2	8.2	7.0	0.2	5.4	6.8
4	EUOR (%)	8.2	8.2	8.2	7.0	2.7	5.4	7.4
5	PH	744	744	720	744	720	744	8,760
6	SH	744	744	720	744	48	744	8,088
7	RSH	0	0	0	0	0	0	0
8	UH	0	0	0	0	672	0	672
9	POH	0	0	0	0	672	0	672
10	FOH & EFOH	18	18	17	15	0	12	175
11	MOH & EMOH	43	43	42	37	1	28	420
12	Oper Mbtu	4,566,925	4,515,406	4,313,633	3,650,958	126,074	3,125,253	45,451,709
13	Net Gen (MWH)	657,017	649,325	619,953	520,970	17,727	443,928	6,516,374
14	ANOHR (Btu/KWH)	6,951	6,954	6,958	7,008	7,112	7,040	6,975
15	NOF (%)	74.7	73.8	72.8	59.2	31.2	50.5	68.2
16	NSC (MW)	1,182	1,182	1,182	1,182	1,182	1,182	1,182
17	ANOHR Equation	-3.7 x NOF + 7227						

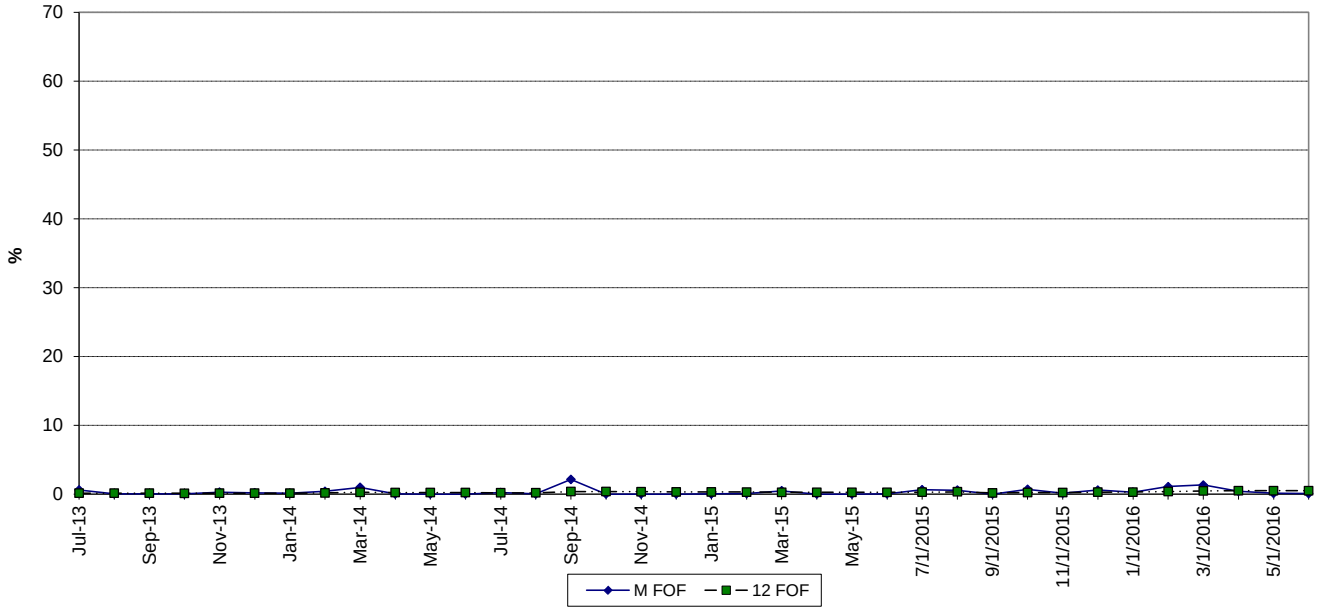
CAPE CANAVERAL 3
FORCED OUTAGE FACTOR



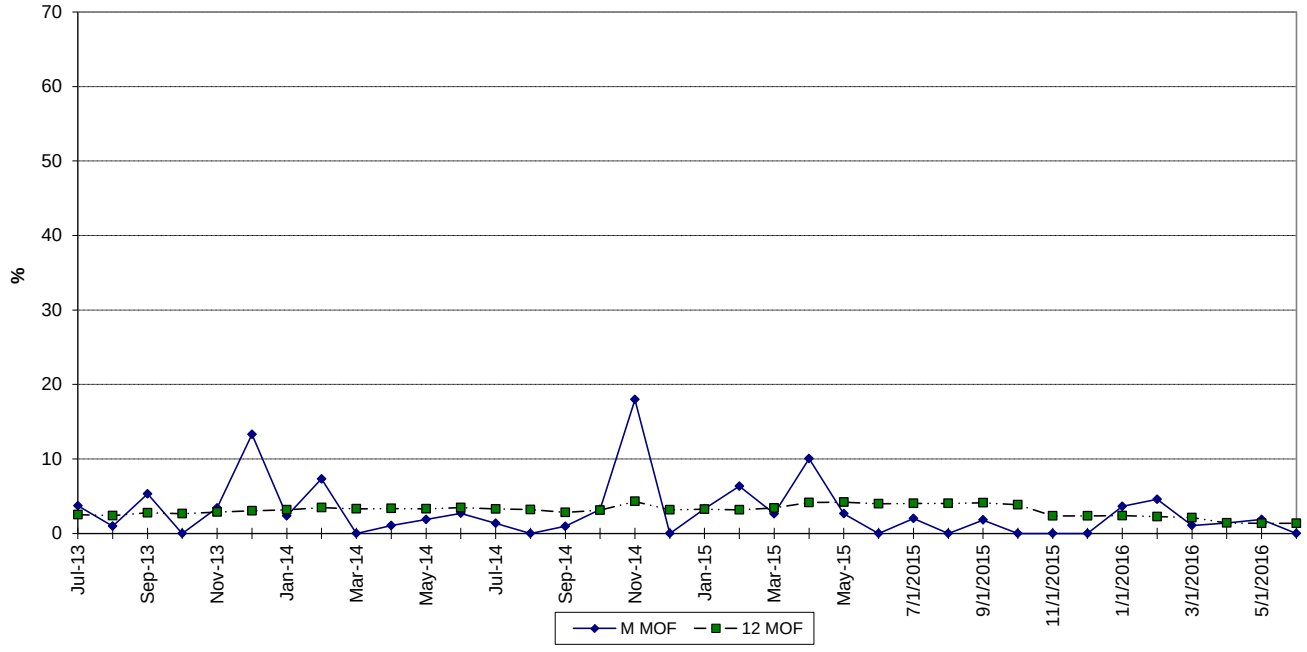
MAINTENANCE OUTAGE FACTOR



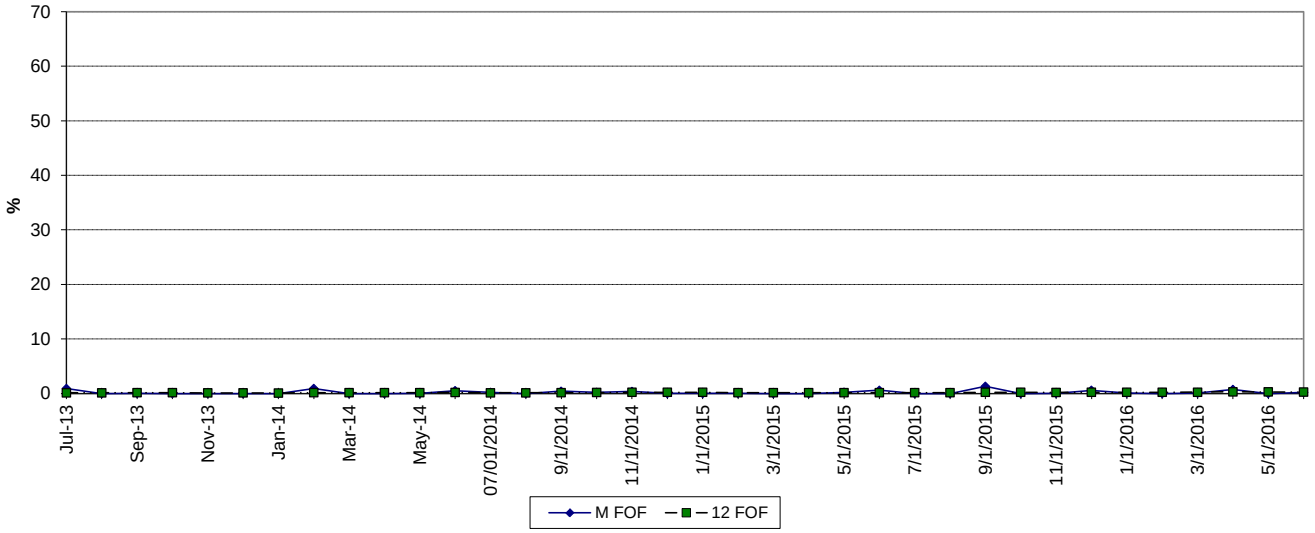
FT. MYERS 2
FORCED OUTAGE FACTOR



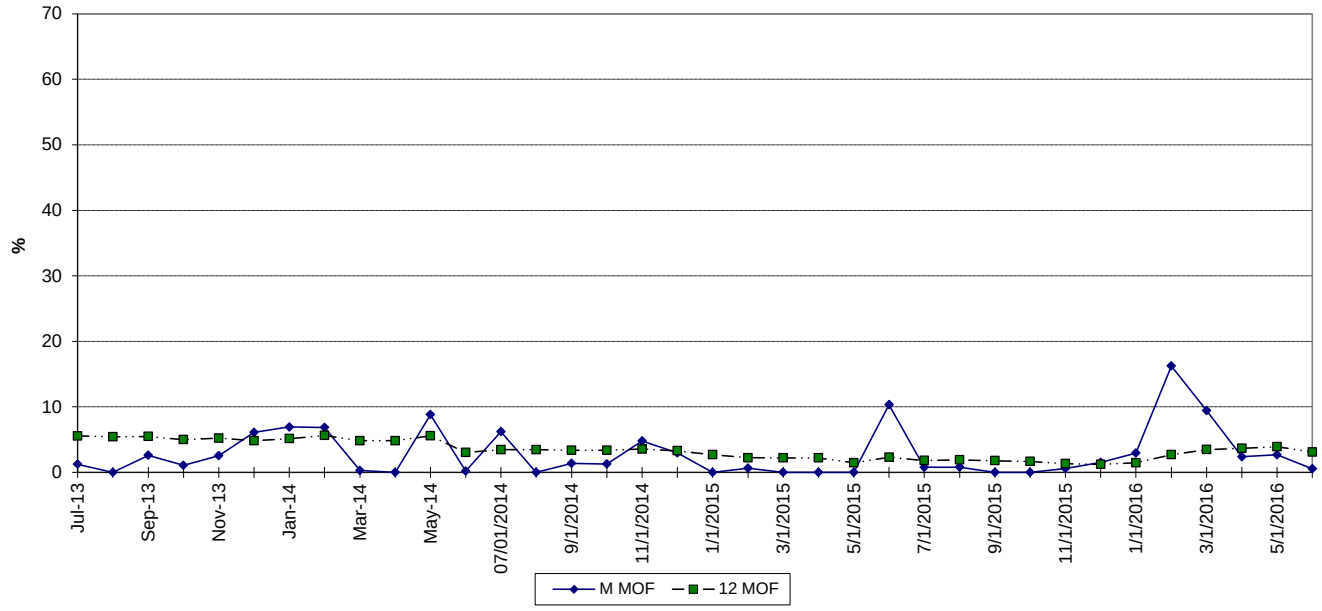
MAINTENANCE OUTAGE FACTOR



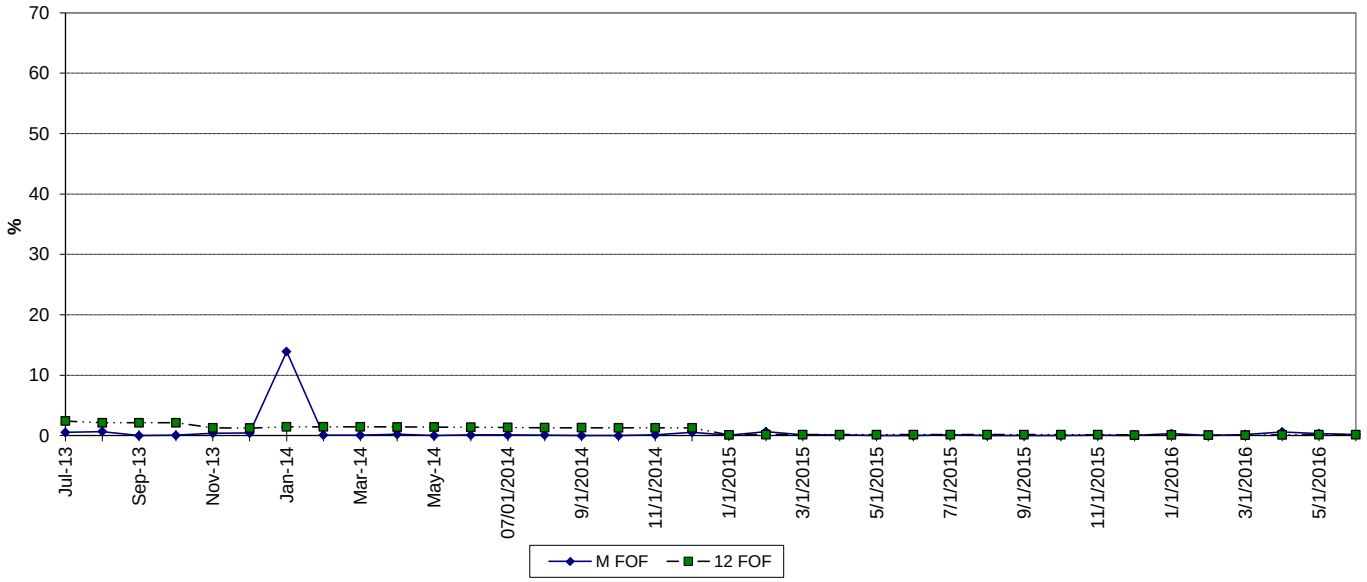
MANATEE 3
FORCED OUTAGE FACTOR



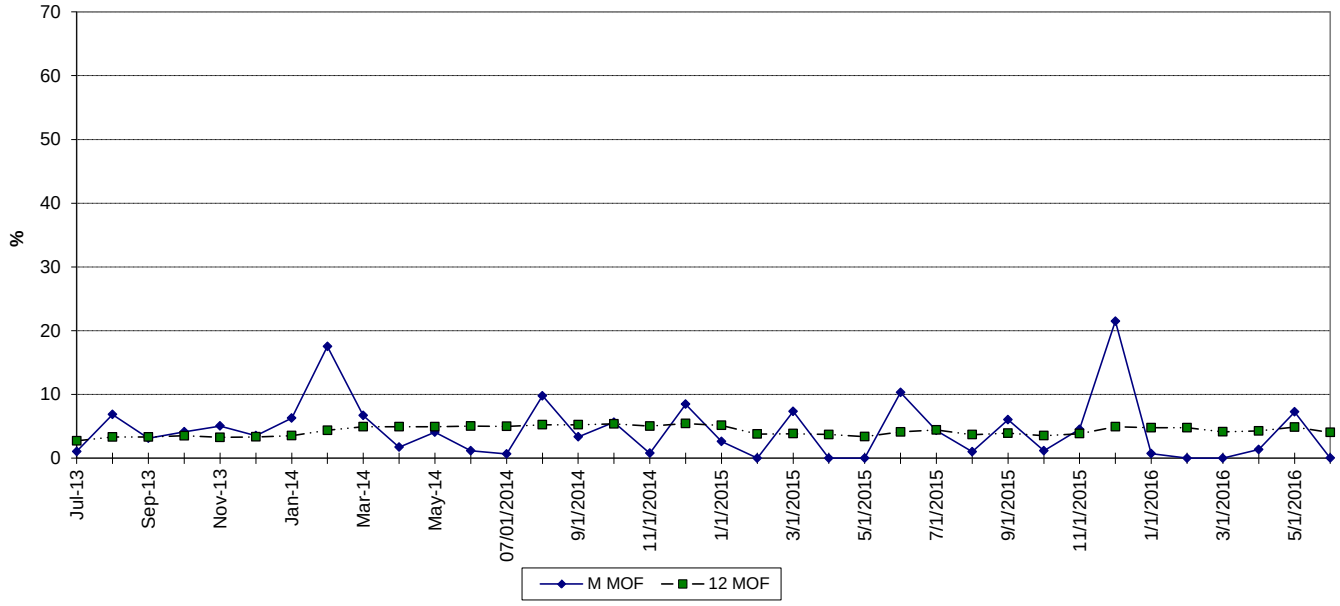
MAINTENANCE OUTAGE FACTOR



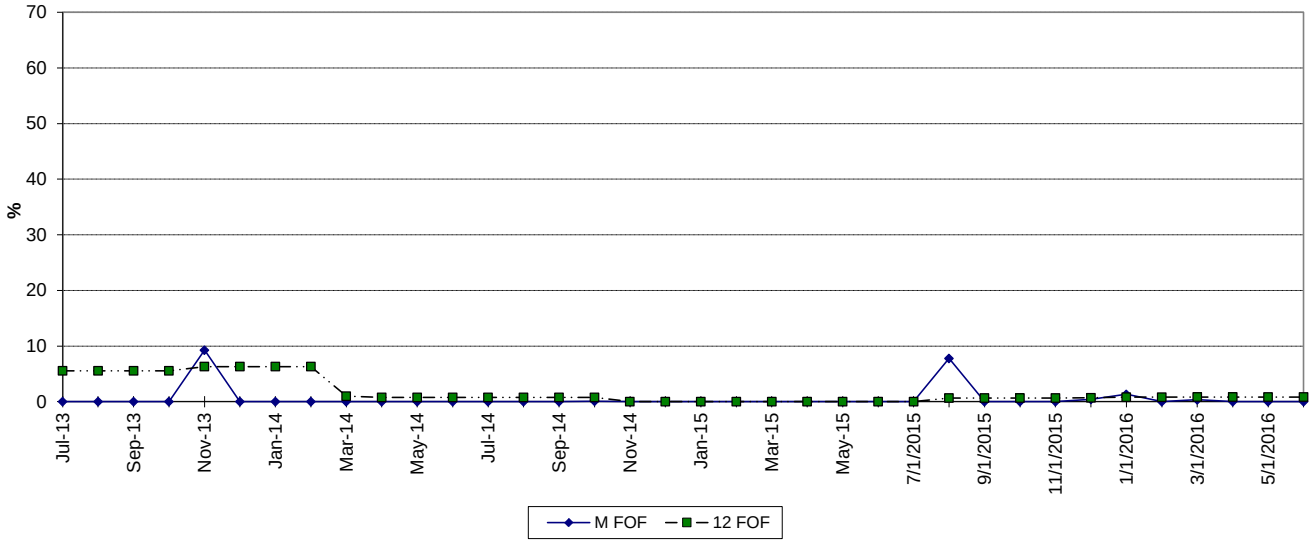
MARTIN 8
FORCED OUTAGE FACTOR



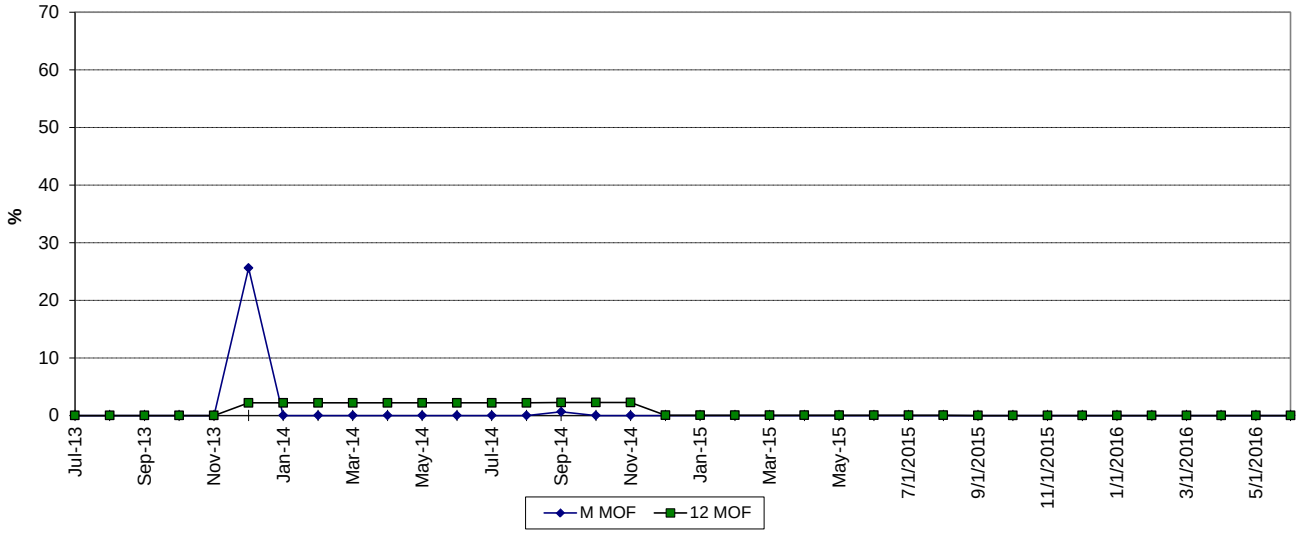
MAINTENANCE OUTAGE FACTOR



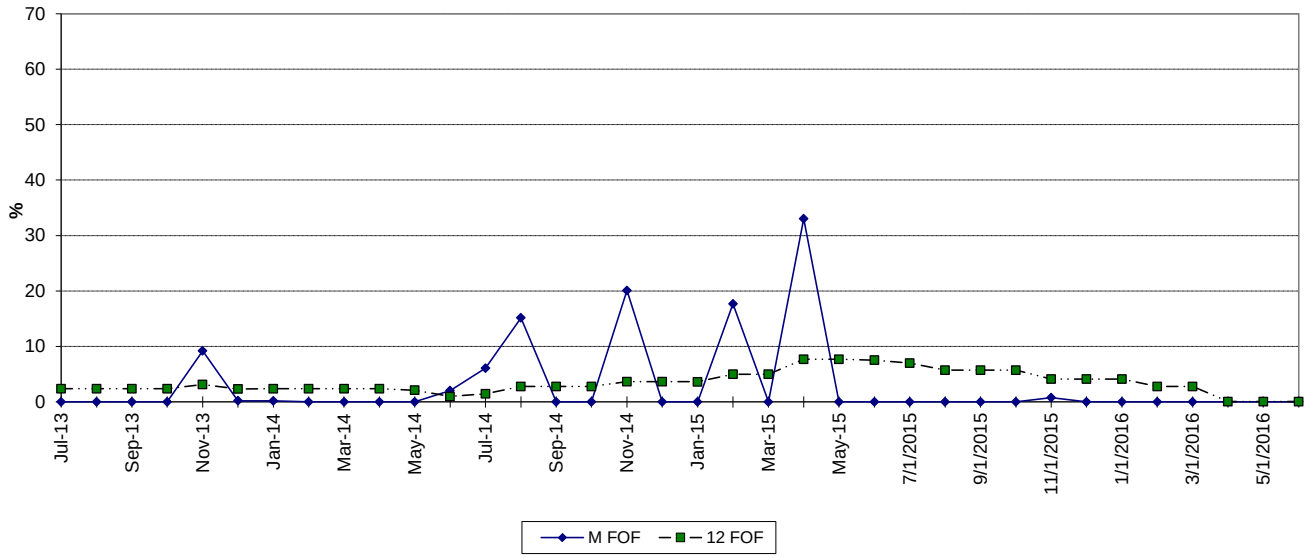
ST. LUCIE 1
FORCED OUTAGE FACTOR



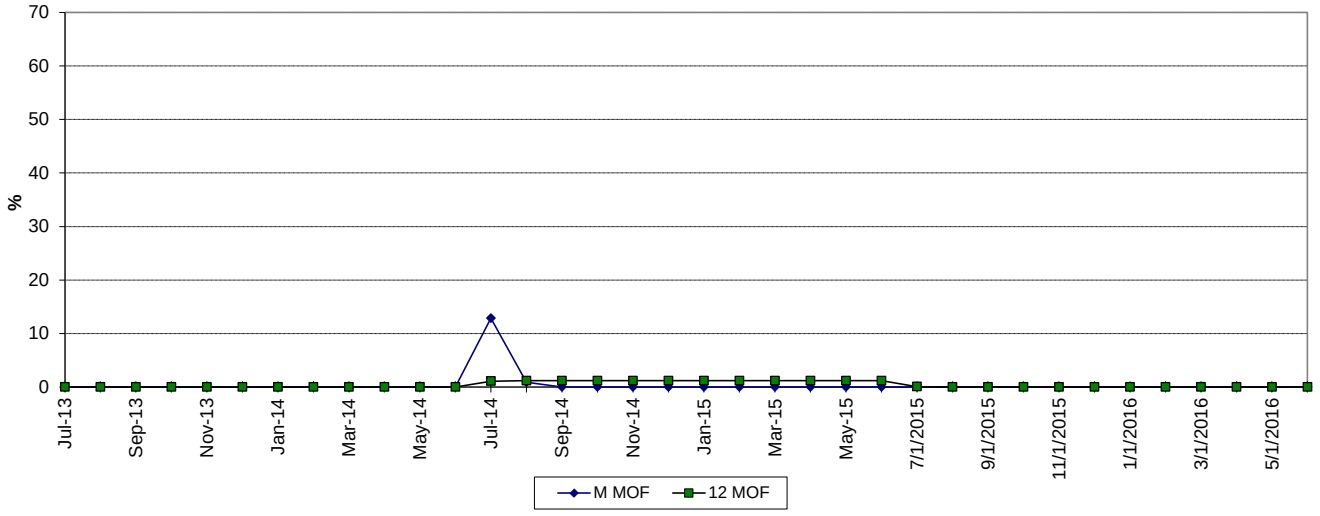
MAINTENANCE OUTAGE FACTOR



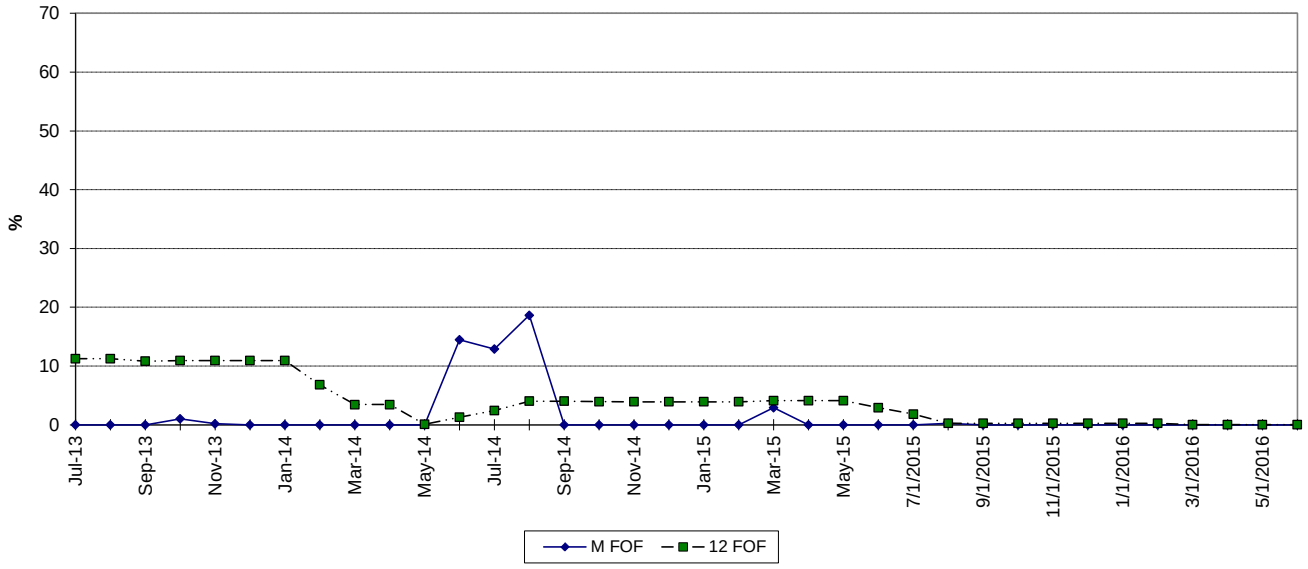
ST. LUCIE 2
FORCED OUTAGE FACTOR



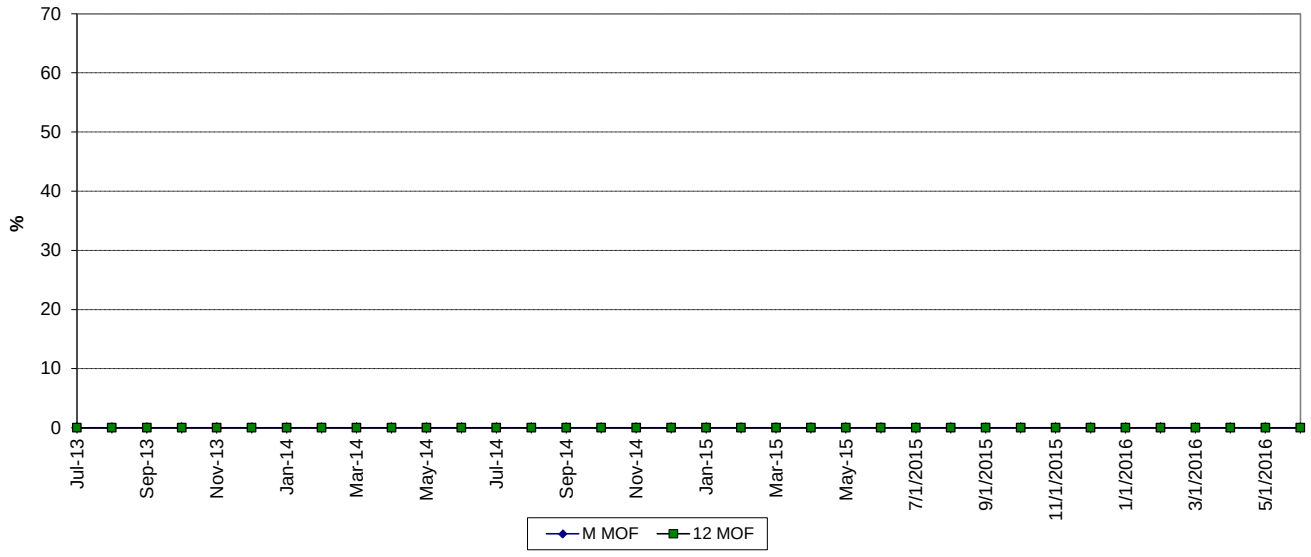
MAINTENANCE OUTAGE FACTOR



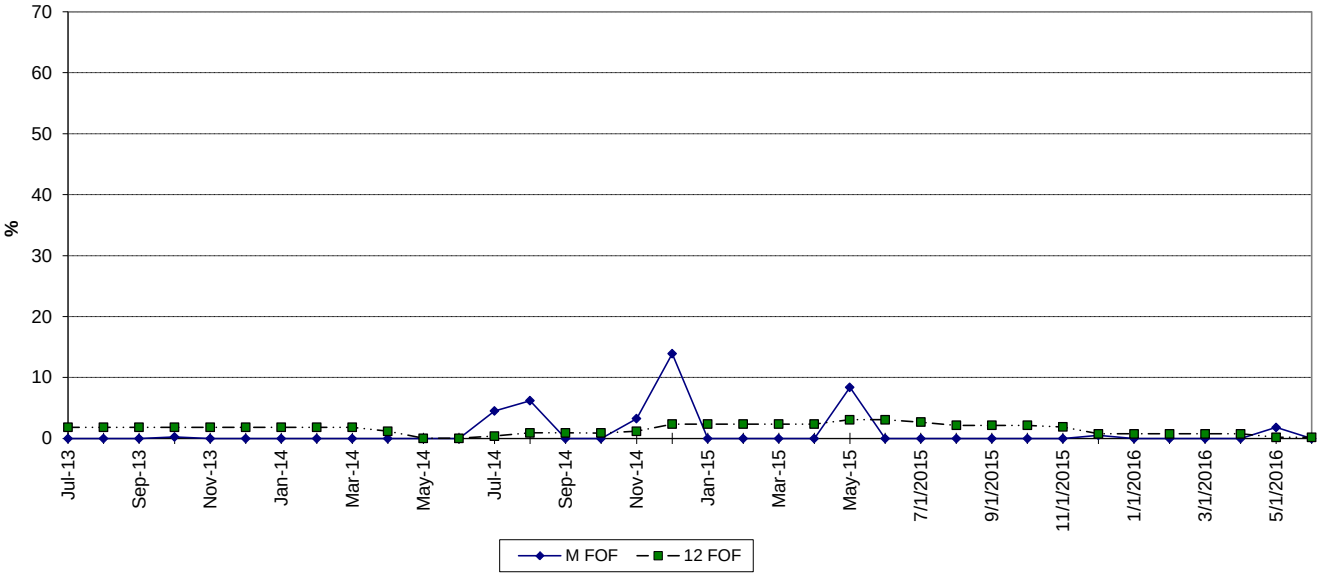
TURKEY POINT 3
FORCED OUTAGE FACTOR



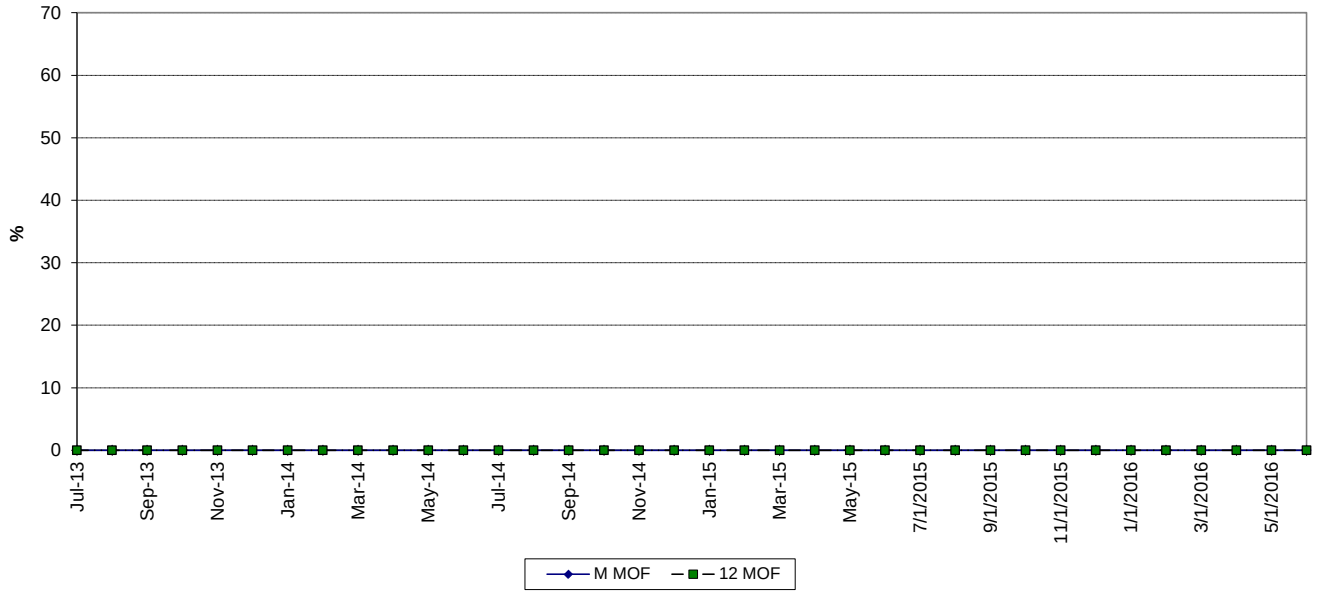
MAINTENANCE OUTAGE FACTOR



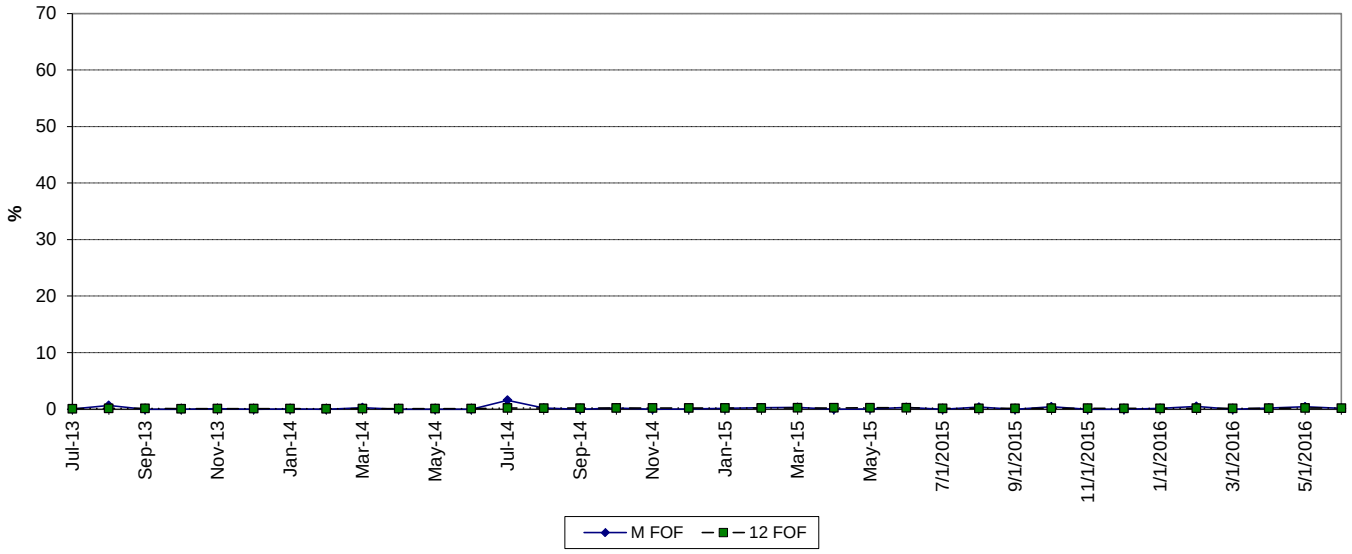
TURKEY POINT 4
FORCED OUTAGE FACTOR



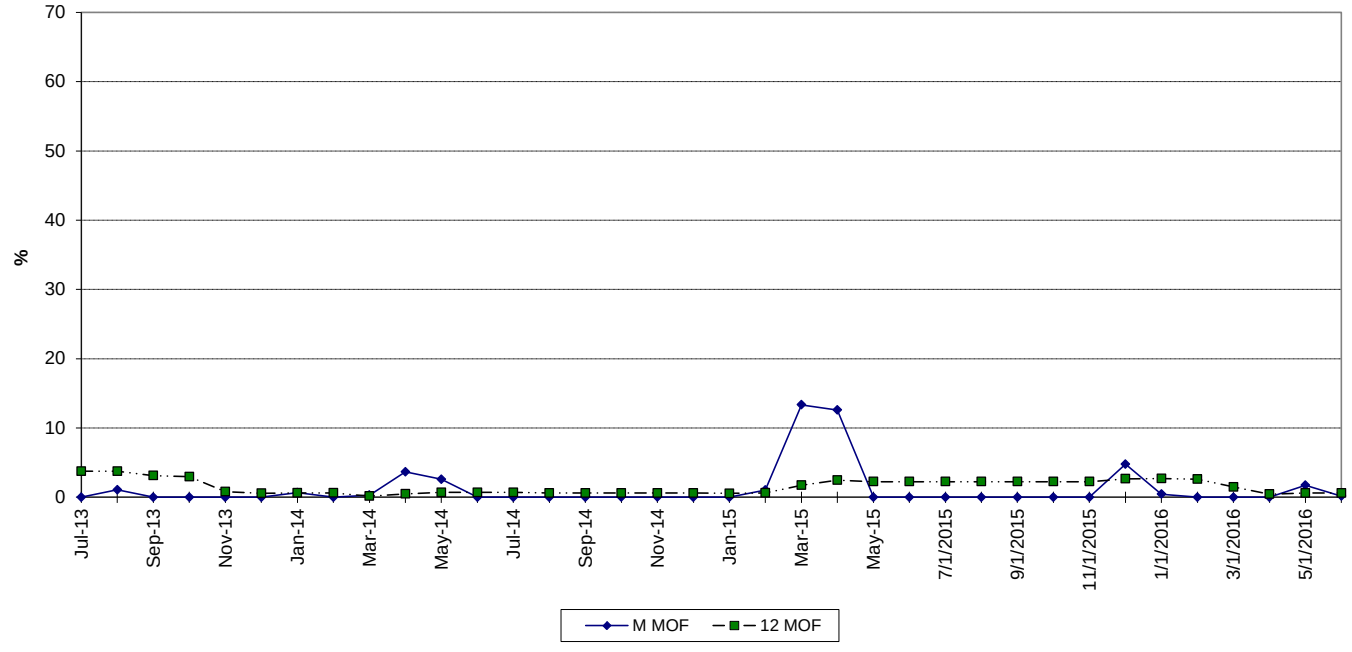
MAINTENANCE OUTAGE FACTOR



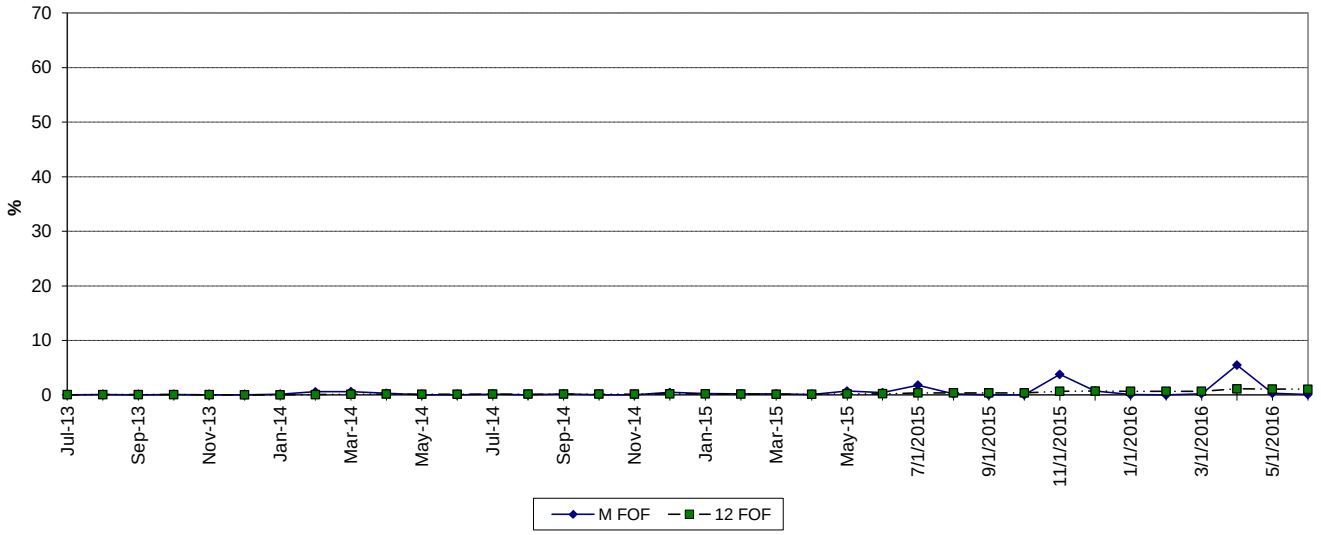
TURKEY POINT 5
FORCED OUTAGE FACTOR



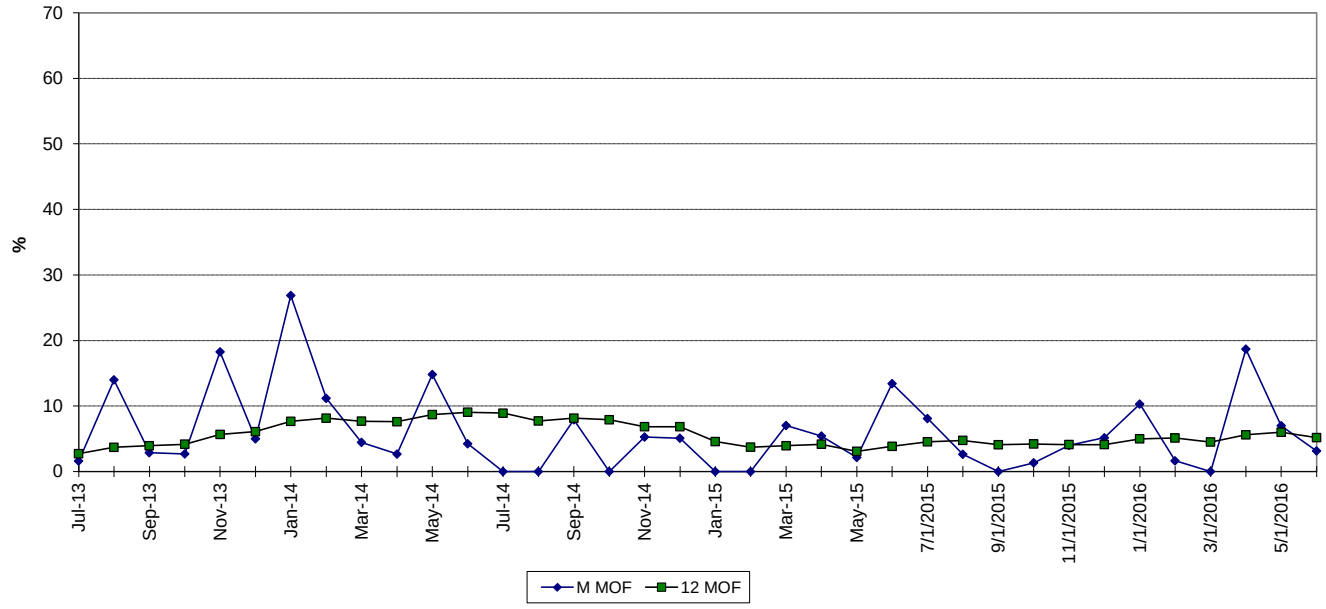
MAINTENANCE OUTAGE FACTOR



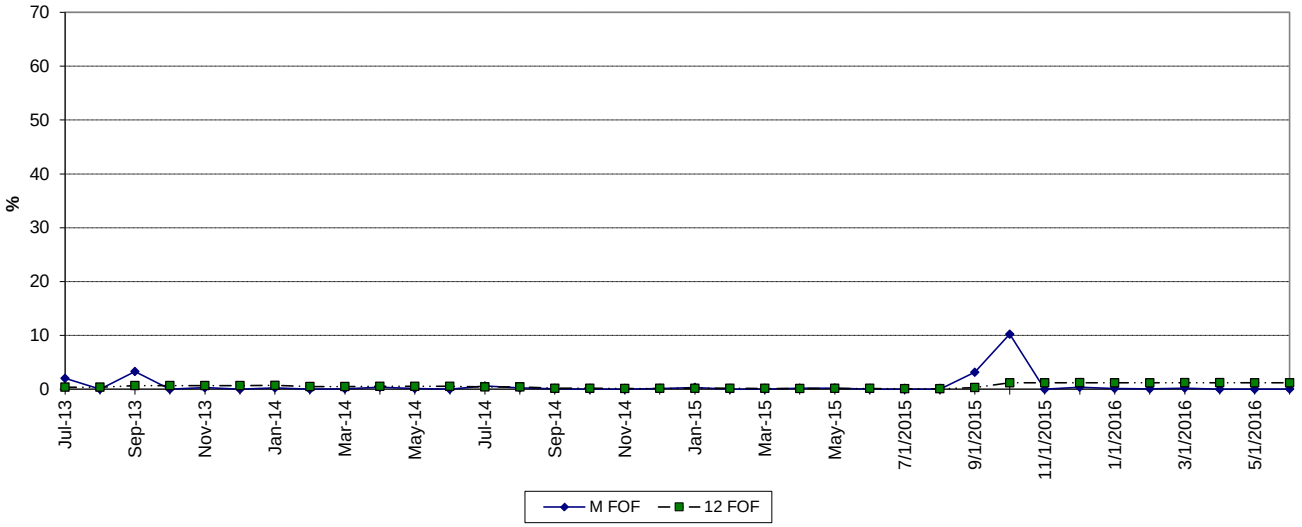
WEST COUNTY 1
FORCED OUTAGE FACTOR



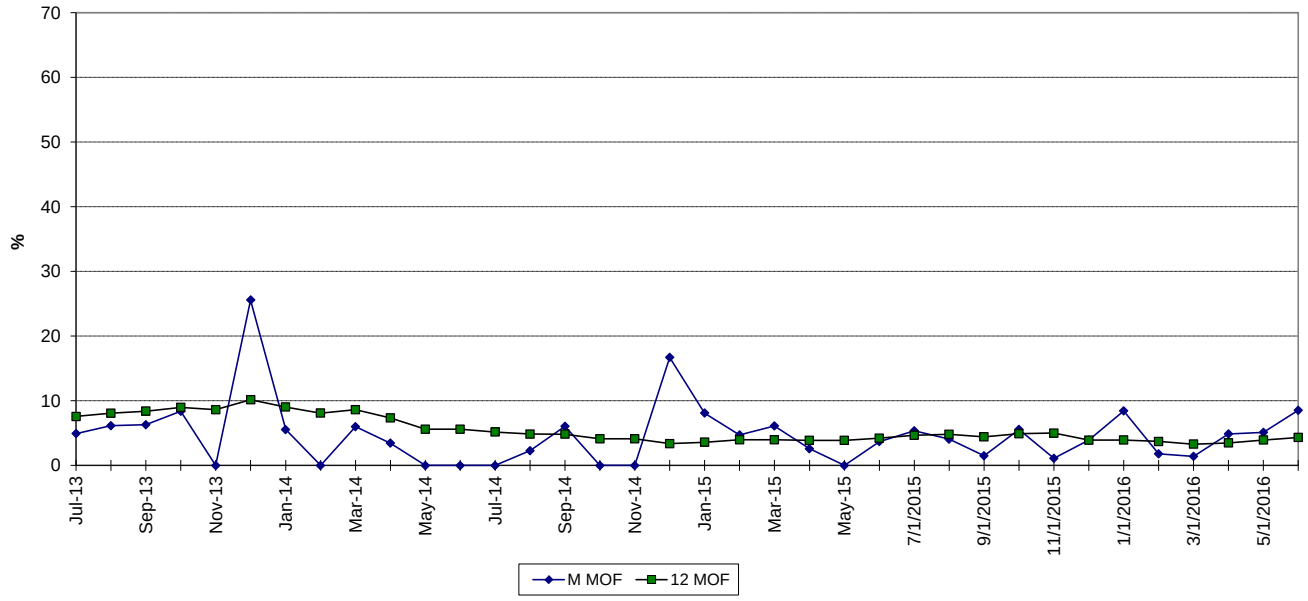
MAINTENANCE OUTAGE FACTOR



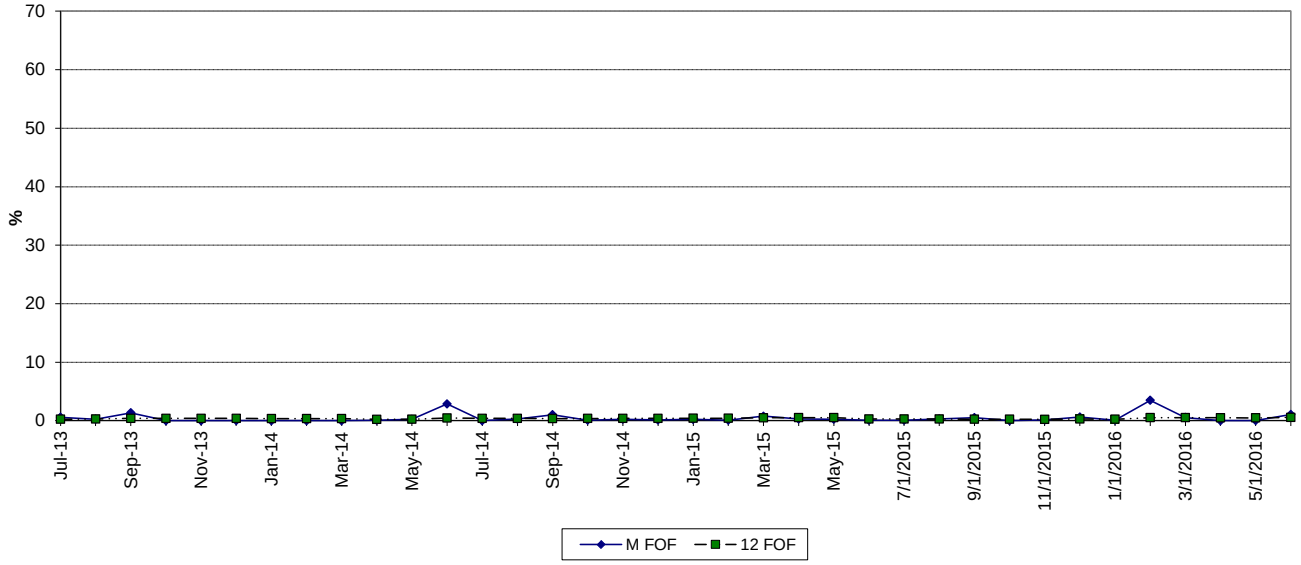
WEST COUNTY 2
FORCED OUTAGE FACTOR



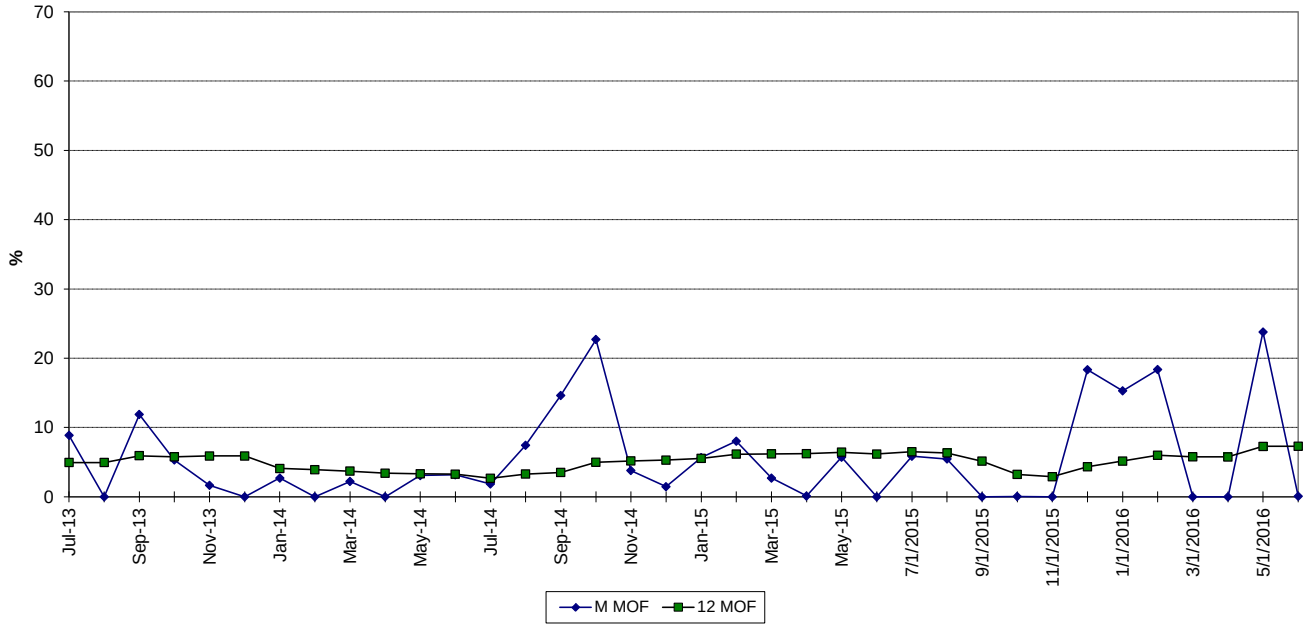
MAINTENANCE OUTAGE FACTOR



WEST COUNTY 3
FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



PLANNED OUTAGE SCHEDULE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY

PERIOD OF: JANUARY THROUGH DECEMBER, 2017

PLANT/UNIT	PLAN OUTAGE	REASON FOR OUTAGE	LR MW*
Cape Canaveral 3	02/15/2017 - 03/23/2017	CT31 - HGP / GEN MINOR / HRSG INSP	410
Cape Canaveral 3	03/25/2017 - 04/30/2017	CT32 - HGP / GEN MINOR / HRSG INSP	410
Cape Canaveral 3	11/13/2017 - 12/19/2017	CT33 - GP / GEN MINOR / HRSG INSP	410
Ft. Myers 2	11/18/2017 - 12/15/2017	ST TURBINE VALVES / BOP / GEN MINOR	534
Manatee 3	03/04/2017 - 05/02/2017	CT3C - .05 UPGRADE / GEN MAJOR / Rewedge / BOP INSP	290
Manatee 3	03/18/2017 - 05/16/2017	CT3D - .05 UPGRADE / GEN MAJOR / Rewedge / BOP INSP	290
Manatee 3	03/25/2017 - 05/23/2017	CT3A - .05 UPGRADE / GEN MAJOR / Rewedge / BOP INSP	290
Manatee 3	03/25/2017 - 06/05/2017	ST MAJOR / GEN MAJOR (REWEDGE) / TURBINE VLVS	1,158
Manatee 3	05/20/2017 - 07/18/2017	CT3B - .05 UPGRADE / GEN MAJOR / Rewedge / BOP INSP	290
Martin 8	01/01/2017 - 02/07/2017	CT8A - Continued .05 Upgrade/CONTROLS / HOT GAS PATH / HRSG INSP	297
Martin 8	01/07/2017 - 03/07/2017	CT8B - .05 Upgrade/CONTROLS / HOT GAS PATH / HRSG INSP	297
Martin 8	01/07/2017 - 03/24/2017	GEN MAJOR / ST80 TURB VLVS / ACT / HP/IP/LP/ CONTROLS / CT8C&D HRSG INSP	1,187
St. Lucie 1	NONE		
St. Lucie 2	02/20/2017 - 03/28/2017	REFUELING	860
Turkey Point 3	03/27/2017 - 04/27/2017	REFUELING	811
Turkey Point 4	10/02/2017 - 11/01/2017	REFUELING	821
Turkey Point 5	09/09/2017 - 11/07/2017	CT5A - .05 UPGRADE / RECOAT INLET FILTER HOUSE / HRSG INSP	272
Turkey Point 5	09/23/2017 - 11/21/2017	CT5B - .05 UPGRADE / RECOAT INLET FILTER HOUSE / HRSG INSP	272
Turkey Point 5	10/28/2017 - 12/26/2017	CT5C - .05 UPGRADE / RECOAT INLET FILTER HOUSE / HRSG INSP	289
Turkey Point 5	11/04/2017 - 11/13/2017	BALANCE OF PLANT OUTAGE	1,155
Turkey Point 5	11/11/2017 - 01/09/2018	CT5D - .05 UPGRADE / RECOAT INLET FILTER HOUSE / HRSG INSP	289
West County 1	02/25/2017 - 03/06/2017	CTA, B & C HRSG INSP / BOP	1,208
West County 2	NONE		
West County 3	04/08/2017 - 05/30/2017	CTB MAJOR / HRSG INSP	399
West County 3	10/21/2017 - 12/12/2017	CTA MAJOR / HRSG INSP	399
West County 3	10/29/2017 - 12/20/2017	CTC MAJOR / HRSG INSP	399
West County 3	11/01/2017 - 11/28/2017	ST VALVES / BOP INSP	1,208

*Approximate load reduction MW are based on the unit's estimated MW rating during the outage period

Schedule A

FLORIDA PUBLIC UTILITIES
FINAL FUEL AND PURCHASED POWER OVER/(UNDER) RECOVERY
FOR THE PERIOD
JANUARY 2015 THROUGH DECEMBER 2015

CONSOLIDATED ELECTRIC DIVISION		
1 JURISDICTIONAL FUEL COSTS (INCL. ALL ADJUSTMENTS)	$	60,313,649
2 JURISDICTIONAL FUEL REVENUES APPLICABLE TO THE PERIOD		63,090,586
3 ACTUAL OVER/(UNDER) RECOVERED FUEL COSTS FOR THE PERIOD		2,776,937
4 ADJUSTMENTS (INCL. REVENUE REFUND TRUE-UP ADJUSTMENT)		(2,907,565)
5 INTEREST		(3,276)
6 TRUE-UP COLLECTED		2,907,565
7 PRIOR PERIOD TRUE-UP (ACTUAL ENDING 12/14)		(4,383,918)
8 ACTUAL OVER/(UNDER) RECOVERY FOR THE PERIOD (LINE 3 + LINE4 + LINE5 + LINE6 + LINE7)		(1,610,257)
9 PROJECTED UNDER-RECOVERY PER PROJECTION FILED 9/5/15		(1,582,148)
10 FINAL FUEL OVER/(UNDER) RECOVERY (LINE 8 - LINE 9)		**(28,109)**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 36
PARTY: FLORIDA PUBLIC UTILITIES COMPANY – (DIRECT)
DESCRIPTION: Curtis D. Young CDY-1

Exhibit No._____
DOCKET NO. 160001-EI
Florida Public Utilities Company
(CDY - 1)
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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 2015 THROUGH DECEMBER 2015

BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

(EXCLUDES LINE LOSS , EXCLUDES TAXES)

CONSOLIDATED

		ACTUAL Jan 2015	ACTUAL Feb 2015	ACTUAL Mar 2015	ACTUAL Apr 2015	ACTUAL May 2015	ACTUAL Jun 2015	Estimated Jul 2015	Estimated Aug 2015	Estimated Sep 2015	Estimated Oct 2015	Estimated Nov 2015	Estimated Dec 2015	Total
Total System Sales - KWH		53,990,967	55,036,962	50,057,566	43,983,737	45,232,412	55,409,936	66,425,190	65,503,963	64,442,739	55,307,927	44,437,589	48,536,197	648,365,185
RockTenn Purchases - KWH		556,381	659,762	696,071	783,500	746,414	536,024	800,000	800,000	800,000	800,000	800,000	800,000	8,778,152
Rayonier Purchases - KWH - On Peak		237,691	58,533	422,848	468,003	275,330	449,708	420,000	420,000	420,000	420,000	420,000	420,000	4,432,113
Rayonier Purchases - KWH - Off Peak		294,869	142,559	605,966	793,018	517,117	829,847	980,000	980,000	980,000	980,000	980,000	980,000	9,063,376
JEA/Gulf Purchases - KWH		57,193,630	54,457,545	44,954,420	44,583,402	54,286,184	57,784,307	62,821,460	67,269,892	66,177,020	56,767,969	45,571,217	47,485,772	659,352,618
System Billing Demand - KW		165,771	182,750	153,003	142,027	152,510	173,029	158,000	158,000	158,000	158,000	158,000	158,000	1,917,090
DEMAND-KW-(network load)		168,011	180,327	139,348	136,493	156,908	161,049	152,317	151,985	152,036	151,763	151,594	151,541	1,853,372
Purchased Power Rates:														
CCA Fuel Costs - $/KWH		0.044260	0.044260	0.044260	0.044260	0.044260	0.044260	0.044260	0.044260	0.044260	0.044260	0.044260	0.044260	
Rayonier Energy Charge - On Peak - $/KWH		0.045630	0.045630	0.045630	0.104780	0.045630	0.104780	0.099580	0.099580	0.099580	0.099580	0.088120	0.090470	
Rayonier Energy Charge - Off Peak - $/KWH		0.045630	0.045630	0.045630	0.054600	0.045630	0.054600	0.058220	0.058220	0.058220	0.058220	0.058220	0.058220	
Base Fuel Costs - $/KWH JEA AND GULF		0.05016	0.05016	0.05016	0.05016	0.05016	0.05016	0.05016	0.05016	0.05016	0.05016	0.05016	0.05016	
Energy Charge - $/KWH		0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	
Demand and Non-Fuel:														
Demand Charge - $/KW		12.25	12.25	12.25	12.25	12.25	12.25	12.25	12.25	12.25	14.31	14.31	14.31	
Customer Charge - $		79,472	79,472	79,472	79,472	79,472	79,472	79,472	79,472	79,472	79,472	79,472	79,472	
Transmission Charge $/KW		1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	
Purchased Power Costs:	RockTenn Fuel Costs	24,625	29,201	30,808	34,678	33,036	23,724	35,408	35,408	35,408	35,408	35,408	35,408	388,520
	Rayonier Standby Costs	24,301	9,176	46,945	92,336	36,159	92,430	98,880	98,880	98,880	98,880	94,066	95,053	885,986
	JEA/Gulf Base Fuel Costs	2,868,676	2,719,393	2,256,528	2,249,994	1,480,448	3,144,720	3,372,457	3,323,552	3,276,256	2,815,571	2,270,645	2,387,622	32,165,862
	JEA Fuel Adjustment	344,813	338,592	269,543	257,011	321,653	384,057	415,757	411,853	398,830	337,264	260,886	251,414	3,991,675
	Subtotal Fuel Costs	3,262,415	3,096,362	2,603,824	2,634,019	1,871,296	3,644,931	3,922,502	3,869,693	3,809,374	3,287,123	2,661,007	2,769,497	37,432,043
Demand and Non-Fuel Costs:	Demand Charge	2,030,023	2,272,993	1,847,313	1,690,246	1,840,258	2,133,885	1,918,820	1,918,820	1,918,820	1,918,820	1,918,820	1,918,820	23,327,638
	Customer Charge	79,472	79,472	79,472	79,472	79,472	79,472	79,472	79,472	79,472	79,472	79,472	79,472	953,667
	FERC & Meter Reading	2,491	2,682	2,530	2,283	2,332	2,619	2,856	2,817	2,818	2,555	2,258	2,433	30,674
	Transmission Charge	329,934	348,055	285,557	233,186	313,114	266,574	291,746	290,837	290,976	290,229	289,767	289,624	3,519,599
Subtotal Demand & Non-Fuel Costs		2,441,920	2,703,202	2,214,872	2,005,187	2,235,176	2,482,550	2,292,894	2,291,946	2,292,086	2,291,076	2,290,317	2,290,349	27,831,578
Total System Purchased Power Costs		5,704,335	5,799,564	4,818,696	4,639,206	4,106,472	6,127,481	6,215,396	6,161,639	6,101,460	5,578,199	4,951,324	5,059,846	65,263,621
Less Direct Billing To GSLD1 Class:	Demand	47,735	108,048	182,954	102,241	47,706	113,576	276,673	276,673	276,673	276,673	276,673	276,673	2,262,298
	Commodity	124,277	186,080	113,442	42,534	16,327	63,612	112,592	120,038	107,310	101,924	93,621	99,067	1,180,824
Net Purchased Power Costs		5,532,323	5,505,436	4,522,300	4,494,431	4,042,439	5,950,293	5,826,131	5,764,928	5,717,477	5,199,602	4,581,030	4,684,106	61,820,499
	Other Fuel Costs	3,042	13,550	5,412	11,694	17,841	56,170	10,300	10,300	10,300	10,300	10,300	10,300	169,509
Total Costs and Charges		5,535,365	5,518,986	4,527,712	4,506,125	4,060,280	6,006,463	5,836,431	5,775,228	5,727,777	5,209,902	4,591,330	4,694,406	61,990,008
Sales Revenues - Fuel Adjustment Revenues:														
RS<	0.10283	1,882,704	1,913,625	1,851,984	1,627,707	1,646,071	1,906,360	1,887,392	1,898,524	1,868,941	1,664,150	1,428,110	1,611,724	21,187,492
RS>	0.11532	1,049,104	1,129,971	810,158	409,559	488,369	976,718	1,706,389	1,616,970	1,547,670	999,719	531,833	843,275	12,109,735
GS	0.10343	510,745	524,797	494,192	468,494	493,428	603,056	633,242	634,633	626,317	568,502	451,676	455,326	6,464,408
GSD	0.09826	1,189,157	1,164,473	1,149,238	1,190,882	1,208,684	1,319,657	1,588,846	1,567,960	1,593,939	1,461,674	1,206,467	1,161,388	15,802,365
GSLD	0.09460	613,228	546,755	555,309	621,958	661,585	699,501	797,295	780,158	766,750	730,197	669,499	664,597	8,106,832
LS	0.08028	50,029	49,455	49,999	49,995	50,116	50,084	50,669	50,635	50,958	50,992	51,075	51,017	605,024
	0.08028	-	-	-	-	-	-	-	-	-	-	0	0	0
Unbilled Fuel Revenues		67,839	(79,601)	(192,182)	(126,932)	272,120	576,001	-	-	-	-	0	0	517,245
Total Fuel Revenues (Excl. GSLD1)		5,362,806	5,249,675	4,718,698	4,241,663	4,820,373	6,131,379	6,663,833	6,548,880	6,454,575	5,475,234	4,338,660	4,787,327	64,793,103
GSLD1 Fuel Revenues		172,012	294,128	296,396	144,775	64,033	177,188	389,265	396,711	383,983	378,597	370,294	375,740	3,443,122
Non-Fuel Revenues		2,288,475	2,321,991	2,160,694	1,928,308	1,973,491	2,332,567	2,546,202	2,585,909	2,188,142	2,301,469	2,211,046	3,202,533	28,040,827
Total Sales Revenue		7,823,293	7,865,794	7,175,788	6,314,746	6,857,897	8,641,134	9,599,300	9,531,500	9,026,700	8,155,300	6,920,000	8,365,600	96,277,052
KWH Sales:	RS<	18,309,598	18,609,349	18,011,385	15,830,816	16,008,065	18,540,689	18,354,491	18,462,747	18,175,055	16,183,508	13,888,070	15,673,674	206,047,447
	RS>	9,097,556	9,798,886	7,025,482	3,551,671	4,235,012	8,469,855	14,796,982	14,021,592	13,420,656	8,669,088	4,611,801	7,312,480	105,011,071
	GS	4,938,223	5,073,287	4,778,233	4,529,765	4,770,840	5,830,817	6,122,420	6,135,874	6,055,466	5,496,491	4,366,969	4,402,267	62,500,653
	GSD	12,339,838	11,864,166	11,729,305	12,133,883	12,310,015	13,439,781	16,169,811	15,957,252	16,221,650	14,875,580	12,278,313	11,819,544	161,139,139
	GSLD	6,482,193	5,779,540	5,869,961	6,574,476	6,993,358	7,394,156	8,428,062	8,246,911	8,105,183	7,718,785	7,077,153	7,025,336	85,695,114
	GSLD1	2,200,000	3,290,000	2,020,000	740,000	290,000	1,110,000	1,922,260	2,048,856	1,829,972	1,729,298	1,579,077	1,667,403	20,426,866
	OL	623,559	621,734	623,200	623,126	625,122	624,638	631,154	630,731	634,756	635,177	636,205	635,493	7,544,895
	SL,CSL	-	-	-	-	-	-	-	-	-	-	-	-	0
Total KWH Sales		53,990,967	55,036,962	50,057,566	43,983,737	45,232,412	55,409,936	66,425,190	65,503,963	64,442,739	55,307,927	44,437,589	48,536,197	648,365,185
True-up Calculation (Excl. GSLD1):														
Fuel Revenues		5,362,806	5,249,675	4,718,698	4,241,663	4,820,373	6,131,379	6,663,833	6,548,880	6,454,575	5,475,234	4,338,660	4,787,327	64,793,103
True-up Provision - collect/(refund)		242,298	242,297	242,297	242,297	242,297	242,297	242,297	242,297	242,297	242,297	242,297	242,297	2,907,565
Gross Receipts Tax Refund														0
Fuel Revenue		5,120,508	5,007,378	4,476,401	3,999,366	4,578,076	5,889,082	6,421,536	6,306,583	6,212,278	5,232,937	4,096,363	4,545,030	61,885,538
Net Purchased Power and Other Fuel Costs		5,535,365	5,518,986	4,527,712	4,506,125	4,060,280	6,006,463	5,836,431	5,775,228	5,727,777	5,209,902	4,591,330	4,694,406	61,990,008
True-up Provision for the Period		(414,857)	(511,608)	(51,311)	(506,759)	517,796	(117,381)	585,105	531,355	484,501	23,035	(494,967)	(149,377)	(104,471)
Interest Provision for the Period		(317)	(333)	(274)	(276)	(321)	(306)	(421)	(328)	(240)	(182)	(181)	(191)	(3,370)
Beginning of Period True-up and Interest Provision		(4,381,872)	(4,554,748)	(4,824,393)	(4,633,681)	(4,898,419)	(4,138,647)	(4,014,038)	(3,187,057)	(2,413,733)	(1,687,175)	(1,422,026)	(1,674,877)	(4,381,872)
True-up Collected or (Refunded)		242,298	242,297	242,297	242,297	242,297	242,297	242,297	242,297	242,297	242,297	242,297	242,297	2,907,565
End of Period, Net True-up and Int. Prov.		(4,554,748)	(4,824,393)	(4,633,681)	(4,898,419)	(4,138,647)	(4,014,038)	(3,187,057)	(2,413,733)	(1,687,175)	(1,422,026)	(1,674,877)	(1,582,148)	(1,582,148)
Beginning True-up Amount		(4,381,872)	(4,554,748)	(4,824,393)	(4,633,681)	(4,898,419)	(4,138,647)	(4,014,038)	(3,187,057)	(2,413,733)	(1,687,175)	(1,422,026)	(1,674,877)	
Ending True-up Amount Before Interest		(4,554,431)	(4,824,060)	(4,633,407)	(4,898,143)	(4,138,326)	(4,013,732)	(3,186,636)	(2,413,405)	(1,686,935)	(1,421,844)	(1,674,696)	(1,581,957)	10% Rule Interest Provision:
Total Beginning and Ending True-up		(8,936,303)	(9,378,808)	(9,457,799)	(9,531,824)	(9,036,745)	(8,152,379)	(7,200,673)	(5,600,462)	(4,100,668)	(3,109,019)	(3,096,721)	(3,256,833)	-2.42%
Average True-up Amount		(4,468,152)	(4,689,404)	(4,728,900)	(4,765,912)	(4,518,373)	(4,076,189)	(3,600,337)	(2,800,231)	(2,050,334)	(1,554,509)	(1,548,361)	(1,628,417)	
Average Annual Interest Rate		0.0850%	0.0850%	0.0700%	0.0700%	0.0850%	0.0900%	0.1400%	0.1400%	0.1400%	0.1400%	0.1400%	0.1400%	
Interest Provision		(317)	(333)	(274)	(276)	(321)	(306)	(421)	(328)	(240)	(182)	(181)	(191)	

Exhibit No._____
DOCKET NO. 160001-EI
Florida Public Utilities Company
(CDY - 1)
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FLORIDA PUBLIC UTILITIES COMPANY

Schedule C1

CALCULATION OF PURCHASED POWER COSTS AND CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD1

ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2015 THROUGH DECEMBER 2015

BASED ON TWELVE MONTHS ACTUAL

(EXCLUDES LINE LOSS , EXCLUDES TAXES)

		2015												
		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		53,990,967	55,036,962	50,057,566	43,983,737	45,232,412	55,409,936	67,469,813	67,758,390	61,258,059	46,999,567	44,782,087	46,365,507	638,345,003
ROCKTENN Purchases - KWH		556,381	659,762	696,071	783,500	746,414	536,024	1,292,530	743,548	740,151	1,746,000	684,172	1,564,838	10,749,391
Rayonier Purchases - KWH - On Peak		237,691	58,533	422,848	468,003	275,330	449,708	307,890	193,406	412,441	249,563	221,334	125,497	3,422,244
Rayonier Purchases - KWH - Off Peak		294,869	142,559	605,966	793,018	517,117	829,847	590,741	621,874	1,001,897	485,993	292,762	66,599	6,243,242
JEA Purchases - KWH		29,674,112	29,136,687	23,196,492	22,117,979	27,680,948	33,051,355	35,346,061	34,125,353	27,949,285	22,245,440	23,144,820	24,077,040	331,747,572
Gulf Purchases - KWH		27,519,518	25,318,858	21,757,928	22,465,423	26,605,236	29,770,105	33,084,608	32,164,697	27,125,234	23,046,822	22,292,503	23,396,033	314,546,965
Southern Purchases - TOTAL PURCHASES		246,196	245,361	243,873	243,749	245,919	194,535	248,124	241,768	252,690	250,734	251,095	249,913	2,914,956
System Billing Demand - JEA KW		74,771	91,750	62,003	51,027	61,510	62,029	72,352	72,800	75,846	55,373	50,803	52,954	803,218
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- Gulf KW		58,275	57,911	57,437	57,844	58,233	58,976	59,232	60,050	60,250	59,819	59,692	59,566	707,485
DEMAND-KW-(network load) JEA TRANS		109,736	122,416	81,911	76,649	98,675	102,073	96,150	100,114	92,901	84,888	84,932	74,683	1,127,129
Purchased Power Rates:														
RockTenn Fuel Costs - $/KWH		0.04426	0.04426	0.04426	0.04426	0.04426	0.04426	0.04426	0.04426	0.04426	0.04426	0.04426	0.04426	
Rayonier -Energy Charge- On Peak - $/KWH		0.04563	0.04563	0.04563	0.10478	0.04563	0.10478	0.04563	0.04563	0.10478	0.04563	0.04563	0.04563	
Rayonier- Energy Charge - Off Peak - $/KWH		0.04563	0.04563	0.04563	0.05460	0.04563	0.05460	0.04563	0.04563	0.05460	0.04563	0.04563	0.04563	
JEA Base Fuel Costs - $/KWH		0.04360	0.04360	0.04360	0.04360	0.04360	0.04360	0.04360	0.04360	0.04360	0.04360	0.04360	0.04360	
JEA Energy Charge - $/KWH		0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	
JEA Demand and Non-Fuel:														
Demand Charge - $/KW		14.31	14.31	14.31	14.31	14.31	14.31	14.31	14.31	14.31	14.31	14.31	14.31	
Distribution Facilities Charge - $														
Transmission Charge $/KW		1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	1.51000	
Gulf Energy Environmenal Line Loss Fctr. 0.97400		0.05574	0.05574	0.05574	0.05574	0.05574	0.05574	0.05574	0.05574	0.05574	0.05574	0.05574	0.05574	
Gulf Fuel Demand and Non-Fuel:														
Capacity Charge-$/KW		10.55000	10.55000	10.55000	10.55000	10.55000	10.55000	10.55000	10.55000	10.55000	10.55000	10.55000	10.55000	
Transmission and Interconnection		2.73760	2.60911	2.60911	2.60911	2.60911	2.60911	2.60911	2.60911	2.60911	2.60911	2.60911	2.60911	
Distribution Charge														
Purchased Power Costs: RockTenn Fuel Costs		24,625	29,201	30,808	34,678	33,036	23,724	57,207	32,909	32,759	77,278	30,281	69,260	475,766
Rayonier Standby Costs		24,301	9,176	46,945	92,336	36,159	92,430	41,005	37,202	97,920	33,564	23,458	8,765	543,261
Gulf Base Fuel Costs		1,574,885	1,448,946	1,245,161	1,285,650	1,522,562	1,703,681	1,893,364	1,840,719	1,552,321	1,318,922	1,275,754	1,338,906	18,000,871
JEA Base Fuel Costs		1,293,791	1,270,447	1,011,367	964,344	(42,114)	1,441,039	1,541,088	1,487,865	1,218,589	969,901	(243,832)	1,049,759	11,962,244
JEA Fuel Adjustment		344,813	338,592	269,543	257,011	321,653	384,057	410,721	396,538	324,771	258,492	268,943	279,775	3,854,909
Subtotal Fuel Costs		3,262,415	3,096,362	2,603,824	2,634,019	1,871,296	3,644,931	3,943,385	3,795,233	3,226,360	2,658,157	1,354,604	2,746,465	34,837,051
Demand and Non-Fuel Costs: JEA Demand Charge		1,069,973	1,312,943	887,263	730,196	880,208	1,173,835	1,035,357	1,041,768	1,085,356	792,388	726,991	757,772	11,494,050
JEA Dist. Facilities Charge		0	0	0	0	0	0	0	0	0	0	0	0	0
JEA Transmission Charge		165,702	184,648	123,686	71,193	149,000	154,130	145,187	151,172	140,281	128,181	128,247	112,771	1,654,398
Gulf Capacity Charge		960,050	960,050	960,050	960,050	960,050	960,050	960,050	960,050	960,050	960,050	960,050	960,050	11,520,600
Southern Transmission/Interc		246,196	245,361	243,873	243,749	245,919	194,535	249,124	241,768	252,690	250,734	251,095	249,913	2,914,957
Meter Reading and Processing														0
Subtotal Demand & Non-Fuel Costs		2,441,921	2,703,202	2,214,872	2,005,188	2,235,177	2,482,550	2,389,718	2,394,758	2,438,377	2,131,353	2,066,383	2,080,506	27,584,005
Total System Purchased Power Costs		5,704,336	5,799,564	4,818,696	4,639,207	4,106,473	6,127,481	6,333,103	6,189,991	5,664,737	4,789,510	3,420,987	4,826,971	62,421,056
Less Direct Billing To GSLD1 Class: Demand		47,735	108,048	182,954	102,241	47,706	113,576	47,706	50,683	217,680	47,706	47,706	195,689	1,209,430
(these 2 amounts (Demand and comodity) should Commodity		124,277	186,080	113,442	42,534	16,327	63,612	75,950	108,306	74,462	22,871	67,607	171,195	1,066,664
Net Purchased Power Costs		5,532,324	5,505,436	4,522,299	4,494,432	4,042,441	5,950,293	6,209,447	6,031,002	5,372,594	4,718,934	3,305,674	4,460,087	60,144,963
Special Costs		3,042	16,822	5,497	11,694	17,841	57,339	49,084	33,992	(11,123)	1,517	1,225	(18,242)	168,687
Total Costs and Charges		5,535,366	5,522,258	4,527,796	4,506,126	4,060,281	6,007,631	6,258,531	6,064,994	5,361,472	4,720,451	3,306,899	4,441,845	60,313,650
Sales Revenues - Fuel Adjustment Revenues:														
RS< 1,000 kwh	0.10283	1,882,704	1,913,825	1,851,984	1,627,707	1,646,071	1,906,360	2,067,894	2,063,061	1,975,265	1,673,464	1,597,682	1,617,512	21,823,529
RS> 1,000 kwh	0.11532	1,049,104	1,129,971	810,158	409,559	488,369	976,718	1,609,840	1,537,920	1,173,029	507,068	399,297	448,955	10,539,988
GS	0.10343	510,745	524,797	494,192	466,494	493,428	603,056	751,164	758,224	687,597	582,196	523,706	503,534	6,901,133
GSD	0.09826	1,189,157	1,164,473	1,149,238	1,190,882	1,208,684	1,319,657	1,566,622	1,577,441	1,468,524	1,225,429	1,128,031	1,092,878	15,281,016
GSLD	0.09460	613,228	546,755	555,309	621,958	661,585	698,501	776,629	796,345	789,641	679,858	700,386	667,724	8,108,919
OL	0.08028	50,029	49,454	49,998	49,994	50,116	50,084	50,212	49,798	49,961	49,712	49,831	50,320	599,509
SL,CSL	0.08028	0	0	0	0	0	0	0	0	0	0	0	0	0
Unbilled Fuel Revenues		67,839	(79,601)	(192,182)	(126,932)	272,120	576,001	88,664	3,221	(426,697)	(209,838)	(110,549)	(25,557)	(163,509)
Total Fuel Revenues (Excl. GSLD1)		5,362,806	5,249,674	4,718,697	4,241,662	4,820,373	6,131,379	6,911,025	6,786,010	5,717,320	4,507,889	4,288,384	4,355,366	63,090,586
GSLD1 Fuel Revenues		172,012	294,128	296,397	144,775	64,032	177,188	123,656	158,989	292,143	70,576	115,313	366,884	2,276,093
Non-Fuel Revenues		2,288,475	2,321,991	2,160,693	1,928,308	1,973,491	2,332,567	2,687,314	2,708,865	2,498,307	2,035,723	1,942,739	1,972,569	26,851,041
Total Sales Revenue		7,823,294	7,865,793	7,175,787	6,314,745	6,857,897	8,641,134	9,721,995	9,653,864	8,507,770	6,614,189	6,346,435	6,694,819	92,217,721
KWH Sales: RS< 1,000 kwh		18,309,598	18,609,349	18,011,385	15,830,816	16,008,065	18,540,689	20,111,897	20,064,696	19,211,346	16,275,549	15,538,496	15,731,389	212,243,275
RS> 1,000 kwh		9,097,556	9,798,886	7,025,482	3,551,671	4,235,012	8,469,855	13,960,127	13,336,449	10,172,213	4,397,163	3,462,598	3,893,215	91,400,227
GS		4,936,223	5,073,287	4,778,233	4,529,765	4,770,840	5,830,817	7,262,839	7,331,113	6,648,221	5,629,130	5,063,590	4,868,556	66,724,614
GSD		12,339,838	11,864,166	11,729,305	12,133,883	12,310,015	13,439,781	15,949,601	16,062,353	14,955,585	12,481,601	11,492,797	11,136,842	155,895,767
GSLD		6,482,193	5,779,540	5,869,961	6,574,476	6,993,358	7,394,156	8,209,440	8,417,852	8,347,000	7,186,512	7,403,508	7,058,252	85,716,248
GSLD1		2,200,000	3,290,000	2,020,000	740,000	290,000	1,110,000	1,350,000	1,920,000	1,300,000	410,000	1,200,000	3,050,000	18,880,000
OL		623,559	621,734	623,200	623,126	625,122	624,638	625,909	625,927	623,694	619,612	621,098	627,253	7,484,872
SL,CSL		0	0	0	0	0	0	0	0	0	0	0	0	0
Total KWH Sales		53,990,967	55,036,962	50,057,566	43,983,737	45,232,412	55,409,936	67,469,813	67,758,390	61,258,059	46,999,567	44,782,087	46,365,507	638,345,003
True-up Calculation (Excl. GSLD1):														
Fuel Revenues		5,362,806	5,249,674	4,718,697	4,241,662	4,820,373	6,131,379	6,911,025	6,786,010	5,717,320	4,507,889	4,288,384	4,355,366	63,090,586
True-up Provision - collect/(refund)		242,298	242,297	242,297	242,297	242,297	242,297	242,297	242,297	242,297	242,297	242,297	242,297	2,907,565
Gross Receipts Tax Refund		0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Revenue		5,120,508	5,007,377	4,476,400	3,999,365	4,578,076	5,889,082	6,668,728	6,543,713	5,475,023	4,265,592	4,046,087	4,113,069	60,183,021
Net Purchased Power and Other Fuel Costs		5,535,366	5,522,258	4,527,796	4,506,126	4,060,281	6,007,631	6,258,531	6,064,994	5,361,472	4,720,451	3,306,899	4,441,845	60,313,650
True-up Provision for the Period		(414,858)	(514,880)	(51,396)	(506,760)	517,795	(118,549)	410,197	478,719	113,552	(454,859)	739,188	(328,776)	(130,628)
Interest Provision for the Period		(317)	(333)	(275)	(277)	(321)	(306)	(262)	(226)	(227)	(211)	(201)	(320)	(3,276)
Beginning of Period True-up and Interest Provision		(4,383,918)	(4,556,795)	(4,829,711)	(4,639,085)	(4,903,825)	(4,144,054)	(4,020,613)	(3,368,381)	(2,647,591)	(2,291,969)	(2,504,742)	(1,523,459)	(4,383,918)
True-up Collected or (Refunded)		242,298	242,297	242,297	242,297	242,297	242,297	242,297	242,297	242,297	242,297	242,297	242,297	2,907,565
End of Period, Net True-up and Int. Prov.		(4,556,795)	(4,829,711)	(4,639,085)	(4,903,825)	(4,144,054)	(4,020,613)	(3,368,381)	(2,647,591)	(2,291,969)	(2,504,742)	(1,523,459)	(1,610,258)	(1,610,257)
Beginning True-up Amount		(4,383,918)	(4,556,795)	(4,829,711)	(4,639,085)	(4,903,825)	(4,144,054)	(4,020,613)	(3,368,381)	(2,647,591)	(2,291,969)	(2,504,742)	(1,523,459)	
Ending True-up Amount Before Interest		(4,556,478)	(4,829,378)	(4,638,810)	(4,903,548)	(4,143,733)	(4,020,307)	(3,368,119)	(2,647,365)	(2,291,742)	(2,504,531)	(1,523,257)	(1,609,938)	10% Rule Interest Provision: -2.58%
Total Beginning and Ending True-up		(8,940,396)	(9,386,173)	(9,468,521)	(9,542,634)	(9,047,559)	(8,164,361)	(7,388,732)	(6,015,746)	(4,939,333)	(4,796,500)	(4,028,000)	(3,133,397)	
Average True-up Amount		(4,470,198)	(4,693,087)	(4,734,261)	(4,771,317)	(4,523,779)	(4,082,181)	(3,694,366)	(3,007,873)	(2,469,667)	(2,398,250)	(2,014,000)	(1,566,698)	
Average Annual Interest Rate		0.0850%	0.0850%	0.0700%	0.0700%	0.0850%	0.0900%	0.0850%	0.0900%	0.1100%	0.1050%	0.1200%	0.2450%	
Interest Provision		(317)	(333)	(275)	(277)	(321)	(306)	(262)	(226)	(227)	(211)	(201)	(320)	

Exhibit No._____

DOCKET NO. 160001-EI

Florida Public Utilities Company

(CDY - 1)

Schedule E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2016 - DECEMBER 2016
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

Florida Division -CONSOLIDATED

Under-recovery of purchased power costs for the period January 2016 - December 2016. (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 2016.)(Estimated)	$	1,289,892

Exhibit No._____
DOCKET NO. 160001-EI
Florida Public Utilities Company
(MC-1)
Page 1 of 3

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 37
PARTY: FLORIDA PUBLIC UTILITIES COMPANY – (DIRECT)
DESCRIPTION: Michael Cassel MC-1

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 2016 THROUGH DECEMBER 2016

BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED

(EXCLUDES LINE LOSS , EXCLUDES TAXES)

CONSOLIDATED

		ACTUAL Jan 2016	ACTUAL Feb 2016	ACTUAL Mar 2016	ACTUAL Apr 2016	ACTUAL May 2016	ACTUAL Jun 2016	Estimated Jul 2016	Estimated Aug 2016	Estimated Sep 2016	Estimated Oct 2016	Estimated Nov 2016	Estimated Dec 2016	Total
Total System Sales - KWH		53,893,217	51,683,075	45,119,750	43,174,769	45,403,697	61,225,524	68,382,290	64,587,492	64,503,875	51,223,741	46,213,261	50,756,002	646,166,694
RockTenn Purchases - KWH		811,013	858,665	940,968	1,124,160	1,410,517	1,432,667	925,000	925,000	925,000	925,000	925,000	925,000	12,127,990
Rayonier Purchases - KWH - On Peak		13,717	49,214	21,965	72,269	49,014	30,936	420,000	420,000	420,000	420,000	420,000	420,000	2,757,115
Rayonier Purchases - KWH - Off Peak		24,430	117,881	16,889	163,834	30,567	54,617	980,000	980,000	980,000	980,000	980,000	980,000	6,288,218
Eight Flags Purchases - KWH - KWH							2,959,000	13,875,000	13,876,000	13,876,000	13,876,000	13,876,000	13,876,000	86,214,000
JEA Purchases - KWH		31,019,771	25,816,385	23,052,511	22,575,281	28,053,849	31,490,116	22,300,000	16,900,000	20,600,000	14,200,000	8,000,000	10,800,000	254,807,913
Gulf Purchases - KWH		27,626,571	23,343,210	21,801,748	21,366,561	25,996,698	30,120,479	31,400,000	32,800,000	28,100,000	21,800,000	22,200,000	21,300,000	307,857,267
Generation Demand - KW - JEA		82,342	75,040	49,414	54,208	62,227	75,174	56,000	57,000	45,000	38,000	48,000	37,000	679,405
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 - JEA		101,339	103,904	90,927	83,024	86,673	106,737	89,000	94,000	89,000	89,000	89,000	89,000	1,101,604
Transmission Demand - KW - Southern		57,572	56,605	55,545	55,215	54,940	55,276	58,200	57,600	58,000	58,200	58,200	57,500	682,853
Purchased Power Rates:														
West Rock Fuel Costs - $/KWH		0.04426	0.03731	0.03731	0.03731	0.03731	0.03731	0.04426	0.04426	0.04426	0.04426	0.04426	0.04426	
Rayonier Energy Charge - On Peak - $/KWH		0.04563	0.03846	0.03846	0.03846	0.03846	0.03846	0.04563	0.09378	0.09378	0.04563	0.09378	0.09378	
Rayonier Energy Charge - Off Peak - $/KWH		0.04563	0.03846	0.03846	0.03846	0.03846	0.03846	0.04563	0.05460	0.05460	0.04563	0.05460	0.05460	
Eight Flags Charge - $/KWH														
Base Fuel Costs - $/KWH JEA		0.04360	0.03675	0.03675	0.03675	0.03675	0.03675	0.04360	0.04360	0.04360	0.04360	0.04360	0.04360	
Base Fuel Costs - $/KWH GULF	0.974	0.05648	0.05648	0.05648	0.05648	0.05648	0.05648	0.05648	0.05648	0.05648	0.05648	0.05648	0.05648	
Energy Charge - $/KWH - JEA		0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	0.01162	
Demand and Non-Fuel:														
Demand Charge - $/KW - JEA		14.31	14.31	14.31	14.31	14.31	14.31	14.31	14.31	14.31	14.31	14.31	14.31	
Demand Charge - $/KW - Gulf		11.15	11.15	11.15	11.15	11.15	11.15	10.55	10.55	10.55	10.55	10.55	10.55	
Distribution Facility Charge		79,472	79,472	79,472	79,472	79,472	79,472	79,472	79,472	79,472	79,472	79,472	79,472	
Transmission Charge $/KW - JEA		1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51	1.51	
Transmission Charge $/KW - Southern		2.94	2.94	2.94	2.94	2.94	2.94	2.83	2.83	2.83	2.83	2.83	2.83	
Purchased Power Costs:														
RockTenn Fuel Costs		35,895	31,475	35,108	41,942	52,626	53,453	40,941	40,941	40,941	40,941	40,941	40,941	496,145
Rayonier Standby Costs		1,741	6,427	1,495	9,080	3,061	3,291	63,882	92,896	92,896	63,882	92,896	92,896	524,443
Eight Flags							768,495	1,178,820	1,178,905	1,178,905	1,178,905	1,178,905	1,178,905	7,841,840
Gulf Base Fuel Costs		1,602,117	1,353,619	1,264,233	1,238,997	1,507,488	1,746,617	1,820,813	1,901,996	1,629,454	1,264,131	1,287,326	1,235,138	17,851,929
JEA Base Fuel Costs		1,352,462	928,333	847,180	841,971	1,030,979	1,157,262	972,280	736,840	898,160	619,120	348,800	470,860	10,204,267
JEA Fuel Adjustment		360,450	299,986	267,870	262,325	325,986	365,915	259,126	196,378	239,372	165,004	92,960	125,496	2,960,868
	Subtotal Fuel Costs	3,352,665	2,619,840	2,415,886	2,394,315	2,920,140	4,095,033	4,335,862	4,147,956	4,079,728	3,331,983	3,041,828	3,144,256	39,679,492
Demand and Non-Fuel Costs:	Demand Capacity Charge	2,192,964	2,068,472	1,721,764	1,790,366	1,905,118	2,090,390	1,761,410	1,775,720	1,604,000	1,503,830	1,646,930	1,489,520	21,570,484
	Distr. Fac. Charge	79,472	79,472	79,472	79,472	79,472	79,472	79,472	79,472	79,472	79,472	79,472	79,472	953,667
	FERC & Meter Reading	2,658	3,044	2,654	2,530	2,495	2,868	2,505	2,505	2,505	2,505	2,505	2,505	31,279
	Transmission Charge	322,010	323,045	285,238	287,436	292,139	323,422	299,048	304,900	298,482	299,048	299,048	297,067	3,630,883
Subtotal Demand & Non-Fuel Costs		2,597,104	2,494,033	2,089,128	2,159,804	2,279,224	2,496,152	2,142,435	2,162,597	1,984,459	1,884,855	2,027,955	1,868,564	26,186,313
Total System Purchased Power Costs		5,949,769	5,113,873	4,505,014	4,554,119	5,199,364	6,591,185	6,478,297	6,310,553	6,064,187	5,216,838	5,069,783	5,012,820	66,065,805
Less Direct Billing To GSLD1 Class:	Demand	106,899	115,595	74,826	60,043	89,610	101,829	269,304	269,304	269,304	269,304	269,304	269,304	2,164,626
	Commodity	145,357	134,380	68,617	70,811	59,586	110,935	197,932	161,673	105,383	144,206	212,815	117,979	1,529,674
Net Purchased Power Costs		5,697,513	4,863,898	4,361,572	4,423,265	5,050,169	6,378,421	6,011,061	5,879,577	5,689,500	4,803,328	4,587,664	4,625,537	62,371,505
	FPL Interconnect	5,918	5,918	5,918	5,918	5,918	5,918	9,503	10,621	11,740	12,857	13,976	15,093	109,298
	Special Costs*	2,108	13,233	758	5,915	42,842	1,631	32,497	31,379	30,260	29,143	28,024	26,907	244,698
Total Costs and Charges		5,705,539	4,883,050	4,368,247	4,435,099	5,098,929	6,385,971	6,053,061	5,921,577	5,731,500	4,845,328	4,629,664	4,667,537	62,725,501
Sales Revenues - Fuel Adjustment Revenues:														
RS<	0.10181	1,840,357	1,873,576	1,703,545	1,561,152	1,633,719	1,964,189	1,978,332	1,948,955	1,945,980	1,648,064	1,537,348	1,743,023	21,378,240
RS>	0.11430	942,572	918,576	505,606	336,989	452,311	1,175,500	1,657,938	1,454,736	1,483,086	690,491	515,282	972,366	11,105,453
GS	0.10162	548,223	506,672	482,590	477,741	512,134	641,616	671,103	646,445	663,862	546,615	459,066	472,729	6,628,796
GSD	0.09702	1,157,540	1,028,803	1,039,853	1,096,403	1,142,676	1,410,059	1,506,787	1,466,933	1,536,643	1,322,679	1,155,435	1,126,457	14,990,269
GSLD	0.09400	670,516	591,275	607,366	640,347	633,718	734,807	821,492	779,506	740,430	685,735	629,677	621,936	8,156,804
LS	0.07206	45,221	45,610	45,289	44,658	44,569	44,964	45,324	45,324	45,324	45,324	45,324	45,324	542,256
Unbilled Fuel Revenues		248,714	(252,365)	88,431	(354,626)	488,522	130,565						(100,000)	249,242
Total Fuel Revenues (Excl. GSLD1)		5,453,144	4,712,146	4,472,680	3,802,664	4,907,649	6,101,700	6,680,976	6,341,899	6,415,325	4,938,908	4,342,132	4,881,835	63,051,059
GSLD1 Fuel Revenues	.17197	252,256	249,975	143,443	130,854	149,196	212,764	467,236	430,977	374,687	413,510	482,119	387,283	3,694,300
Non-Fuel Revenues		2,288,475	2,321,991	2,160,694	1,928,308	1,973,491	2,332,567	2,546,202	2,585,909	2,188,142	2,301,469	2,211,046	3,202,533	28,040,827
Total Sales Revenue		7,965,947	7,185,941	6,599,473	5,824,022	7,033,635	8,765,958	9,694,414	9,358,785	8,978,154	7,653,888	7,035,297	8,471,651	94,567,185
KWH Sales:	RS<	18,078,318	18,403,858	16,733,792	15,334,785	16,051,400	19,295,234	19,432,235	19,143,682	19,114,460	16,188,168	15,100,653	17,120,904	209,997,488
	RS>	8,246,639	8,036,696	4,423,592	2,948,341	3,957,302	10,264,547	14,505,432	12,727,606	12,975,644	6,041,166	4,508,244	8,507,314	97,162,523
	GS	5,293,378	4,986,082	4,759,531	4,701,392	5,039,862	6,321,298	6,604,247	6,361,592	6,532,991	5,379,177	4,517,615	4,652,070	65,149,234
	GSD	11,944,137	10,613,334	10,722,279	11,316,383	11,782,352	14,633,463	15,530,657	15,119,877	15,838,395	13,633,033	11,909,227	11,610,547	154,653,684
	GSLD	7,132,968	6,290,000	6,461,176	6,812,036	6,741,513	7,816,901	8,739,059	8,292,408	7,876,725	7,294,870	6,698,529	6,616,174	86,772,359
	GSLD1	2,570,000	2,720,000	1,390,000	1,440,000	1,210,000	2,250,000	2,941,667	2,313,333	1,536,667	2,058,333	2,850,000	1,620,000	24,900,000
	LS	627,777	633,105	629,380	621,832	621,268	624,081	628,994	628,994	628,994	628,994	628,994	628,994	7,531,407
	Total KWH Sales	53,893,217	51,683,075	45,119,750	43,174,769	45,403,697	61,225,524	68,382,290	64,587,492	64,503,875	51,223,741	46,213,261	50,756,002	646,166,694
True-up Calculation (Excl. GSLD1):														
Fuel Revenues		5,453,144	4,712,146	4,472,680	3,802,664	4,907,649	6,101,700	6,680,976	6,341,899	6,415,325	4,938,908	4,342,132	4,881,835	63,051,059
True-up Provision - collect/(refund)		131,846	131,846	131,846	131,846	131,846	131,846	131,846	131,846	131,846	131,846	131,842	1,582,148	
Gross Receipts Tax Refund														0
Fuel Revenue		5,321,298	4,580,300	4,340,834	3,670,818	4,775,803	5,969,854	6,549,130	6,210,053	6,283,479	4,807,062	4,210,286	4,749,993	61,468,911
Net Purchased Power and Other Fuel Costs		5,705,539	4,883,050	4,368,247	4,435,099	5,098,929	6,385,971	6,053,061	5,921,577	5,731,500	4,845,328	4,629,664	4,667,537	62,725,501
True-up Provision for the Period		(384,241)	(302,749)	(27,414)	(764,281)	(323,125)	(416,117)	496,069	288,476	551,979	(38,266)	(419,378)	82,456	(1,256,590)
Interest Provision for the Period		(491)	(561)	(553)	(636)	(819)	(893)	(319)	(258)	(193)	(148)	(159)	(163)	(5,193)
Beginning of Period True-up and Interest Provision		(1,610,257)	(1,863,143)	(2,034,607)	(1,930,728)	(2,563,799)	(2,755,897)	(3,041,061)	(2,413,465)	(1,993,401)	(1,309,769)	(1,216,336)	(1,504,027)	(1,610,257)
True-up Collected or (Refunded)		131,846	131,846	131,846	131,846	131,846	131,846	131,846	131,846	131,846	131,846	131,846	131,842	1,582,148
End of Period, Net True-up and Int. Prov.		(1,863,143)	(2,034,607)	(1,930,728)	(2,563,799)	(2,755,897)	(3,041,061)	(2,413,465)	(1,993,401)	(1,309,769)	(1,216,336)	(1,504,027)	(1,289,892)	(1,289,892)
Beginning True-up Amount		(1,610,257)	(1,863,143)	(2,034,607)	(1,930,728)	(2,563,799)	(2,755,897)	(3,041,061)	(2,413,465)	(1,993,401)	(1,309,769)	(1,216,336)	(1,504,027)	
Ending True-up Amount Before Interest		(1,862,652)	(2,034,046)	(1,930,175)	(2,563,163)	(2,755,078)	(3,040,168)	(2,413,146)	(1,993,143)	(1,309,576)	(1,216,188)	(1,503,868)	(1,289,729)	
Total Beginning and Ending True-up		(3,472,909)	(3,897,190)	(3,964,782)	(4,493,891)	(5,318,877)	(5,796,066)	(5,454,207)	(4,406,608)	(3,302,976)	(2,525,957)	(2,720,205)	(2,793,756)	
Average True-up Amount		(1,736,455)	(1,948,595)	(1,982,391)	(2,246,946)	(2,659,439)	(2,898,033)	(2,727,104)	(2,203,304)	(1,651,488)	(1,262,978)	(1,360,102)	(1,396,878)	
Average Annual Interest Rate		0.3400%	0.3450%	0.3350%	0.3400%	0.3700%	0.3700%	0.1400%	0.1400%	0.1400%	0.1400%	0.1400%	0.1400%	
Interest Provision		(491)	(561)	(553)	(636)	(819)	(893)	(319)	(258)	(193)	(148)	(159)	(163)	

10% Rule Interest Provision:
-1.95%

* Includes: Consulting fees, Legal fees and Taxes on Company Use.

Exhibit No._____
DOCKET NO. 160001-EI
Florida Public Utilities Compa
(MC-1)
Page 2 of 3

FLORIDA PUBLIC UTILITIES COMPANY
CONSOLIDATED FLORIDA DIVISIONS
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
JANUARY 2016 - DECEMBER 2016

	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)	31,017,064	32,446,865	(1,429,801)	-4.4%	562,665	572,000	(9,335)	-1.6%	5.51253	5.67253	(0.16000)	-2.8%
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)	26,186,313	25,974,799	211,514	0.8%	562,665	572,000	(9,335)	-1.6%	4.65398	4.54105	0.11293	2.5%
11 Energy Payments to Qualifying Facilities (A8a)	8,862,428	5,174,850	3,687,578	71.3%	107,387	111,155	(3,768)	-3.4%	8.25279	4.65553	3.59726	77.3%
12 TOTAL COST OF PURCHASED POWER	66,065,805	63,596,514	2,469,291	3.9%	670,052	683,155	(13,103)	-1.9%	9.85980	9.30924	0.55056	5.9%
13 TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					670,052	683,155	(13,103)	-1.9%				
14 Fuel Cost of Economy Sales (A7)												
15 Gain on Economy Sales (A7a)												
16 Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17 Fuel Cost of Other Power Sales (A7)	353,996	504,000	(150,004)	-29.8%								
18 TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	353,996	504,000	(150,004)	-29.8%	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)	66,419,801	64,100,514	2,319,287	3.6%	670,052	683,155	(13,103)	-1.9%	9.91263	9.38301	0.52962	5.6%
21 Net Unbilled Sales (A4)	275,769 *	0 *	275,769	0.0%	2,782	0	2,782	0.0%	0.04268	0.00000	0.04268	0.0%
22 Company Use (A4)	57,196 *	56,392 *	804	1.4%	577	601	(24)	-4.0%	0.00885	0.00856	0.00029	3.4%
23 T & D Losses (A4)	2,034,666 *	2,203,037 *	(168,371)	-7.6%	20,526	23,479	(2,953)	-12.6%	0.31488	0.33426	(0.01938)	-5.8%
24 SYSTEM KWH SALES	66,419,801	64,100,514	2,319,287	3.6%	646,167	659,075	(12,908)	-2.0%	10.27904	9.72583	0.55321	5.7%
25 Wholesale KWH Sales												
26 Jurisdictional KWH Sales	66,419,801	64,100,514	2,319,287	3.6%	646,167	659,075	(12,908)	-2.0%	10.27904	9.72583	0.55321	5.7%
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	66,419,801	64,100,514	2,319,287	3.6%	646,167	659,075	(12,908)	-2.0%	10.27904	9.72583	0.55321	5.7%
28 GPIF**												
29 TRUE-UP**	1,582,148	1,582,148	0	0.0%	646,167	659,075	(12,908)	-2.0%	0.24485	0.24006	0.00479	2.0%
30 TOTAL JURISDICTIONAL FUEL COST	68,001,949	65,682,662	2,319,287	3.5%	646,167	659,075	(12,908)	-2.0%	10.52390	9.96589	0.55801	5.6%
31 Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
32 Fuel Factor Adjusted for Taxes									10.53148	9.97307	0.55841	5.6%
33 FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									10.531	9.973	0.558	5.6%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

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DOCKET NO. 160001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(MC-1)
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Docket No. 160001-EI

DOCKET NO. 160001-EI: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

EXHIBIT _____ (MC-2)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 38
PARTY: FLORIDA PUBLIC UTILITIES COMPANY – (DIRECT)
DESCRIPTION: Michael Cassel MC-2

FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

	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)	23,503,028		463,800	5.06749
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)	27,383,173		463,800	5.90409
10a	Demand Costs of Purchased Power	24,202,735	*		
10b	Non-fuel Energy & Customer Costs of Purchased Power	3,180,438	*		
11	Energy Payments to Qualifying Facilities (E8a)	14,039,282		194,410	7.22148
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	64,925,483		658,210	9.86395
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	64,925,483		658,210	9.86395
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)	64,925,483		658,210	9.86395
21	Net Unbilled Sales	0	*	0	0.00000
22	Company Use	65,497	*	664	0.01026
23	T & D Losses	1,912,028	*	19,384	0.29961
24	SYSTEM MWH SALES	64,925,483		638,162	10.17382
25	Wholesale MWH Sales				
26	Jurisdictional MWH Sales	64,925,483		638,162	10.17382
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	64,925,483		638,162	10.17382
27a	GSLD1 MWH Sales			23,553	
27b	Other Classes MWH Sales			614,609	
27c	GSLD1 CP KW			576,000	*
28	Projected Unbilled Revenues	0		614,609	0.00000
29	GPIF **				
30	TRUE-UP (OVER) UNDER RECOVERY **	1,289,892		614,609	0.20987
31	TOTAL JURISDICTIONAL FUEL COST	66,215,375		614,609	10.77358
31a	Demand Purchased Power Costs (Line 10a)	24,202,735	*		
31b	Non-demand Purchased Power Costs (Lines 6 + 10b + 11)	40,722,748	*		
31c	True up Over/Under Recovery (Line 29)	1,289,892	*		
31d	Unbilled Revenues	0			

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales

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DOCKET NO. 160001-EI
FLORIDA PUBLIC UTILITIES COMPANY
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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

	FLORIDA DIVISION-CONSOLIDATED	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
	APPORTIONMENT OF DEMAND COSTS			
31	Total Demand Costs (Line 31a)	24,202,735		
32	GSLD1 Portion of Demand Costs (Line 31a) Including Line Losses(Line 27c x $5.85)	3,585,384	576,000 (KW)	$6.22 /KW
33	Balance to Other Classes	20,617,351	614,609	3.35455
	APPORTIONMENT OF NON-DEMAND COSTS			
34	Total Non-demand Costs(Line 31b)	40,722,748		
35	Total KWH Purchased (Line 12)		658,210 KWH	
36	Average Cost per KWH Purchased			6.18689
37	Average Cost Adjusted for Line Losses (Line 36 x 1.03)			6.37250
38	GSLD1 Non-demand Costs (Line 27a x Line 37)	1,519,207	23,553	6.45016
39	Balance to Other Classes	39,203,541	614,609	6.37861
	GSLD1 PURCHASED POWER COST RECOVERY FACTORS			
40a	Total GSLD1 Demand Costs (Line 32)	3,585,384	576,000 (KW)	$6.22 /KW
40b	Revenue Tax Factor			1.00072
40c	GSLD1 Demand Purchased Power Factor Adjusted for Taxes & Rounded			$6.22 /KW
40d	Total Current GSLD1 Non-demand Costs(Line 38)	1,519,207	23,553	6.45016
40e	Total Non-demand Costs Including True-up	1,519,207	23,553	6.45016
40f	Revenue Tax Factor			1.00072
40g	GSLD1 Non-demand Costs Adjusted for Taxes & Rounded			6.45480
	OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a	Total Demand & Non-demand Purchased Power Costs of Other Classes(Line 33 + 39)	59,820,892	614,609	9.73316
41b	Less: Total Demand Cost Recovery	20,617,351 ***		
41c	Total Other Costs to be Recovered	39,203,541	614,609	6.37861
41d	Unbilled Revenue	0	614,609	0.00000
41e	Other Classes' Portion of True-up (Line 30c)	1,289,892	614,609	0.20987
41f	Total Demand & Non-demand Costs Including True-up	40,493,433	614,609	6.58849
42	Revenue Tax Factor			1.00072
43	Other Classes Purchased Power Factor Adjusted for Taxes & Rounded	40,522,589		6.593

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
*** Calculation on Schedule E1 Page 3

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FLORIDA PUBLIC UTILITIES COMPANY
(MC-2)
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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

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	303,969,401	57.025%	60,850.0	1.089	1.030	66,265.7	313,088,483	56.89%	49.46%
45	GS	67,839,464	65.083%	11,899.0	1.089	1.030	12,958.0	69,874,648	11.13%	11.04%
46	GSD	149,642,467	75.900%	22,506.6	1.089	1.030	24,509.7	154,131,741	21.05%	24.35%
47	GSLD	86,498,273	85.182%	11,591.9	1.089	1.030	12,623.6	89,093,221	10.84%	14.07%
48	LS	6,659,912	782.723%	97.1	1.089	1.030	105.7	6,859,709	0.09%	1.08%
49		0	782.723%	0.0	1.089	1.030	0.0	0	0.00%	0.00%
	TOTAL	614,609,517		106,944.6			116,462.7	633,047,802	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	52.53%	3.80%	56.33%	$11,613,754	0.03821	0.03824	0.06593	0.10417
51	GS	10.27%	0.85%	11.12%	2,292,649	0.03380	0.03382	0.06593	0.09975
52	GSD	19.43%	1.87%	21.30%	4,391,496	0.02935	0.02937	0.06593	0.09530
53	GSLD	10.01%	1.08%	11.09%	2,286,464	0.02643	0.02645	0.06593	0.09238
54	LS	0.08%	0.08%	0.16%	32,988	0.00495	0.00495	0.06593	0.07088
	TOTAL	92.32%	7.68%	100.00%	$20,617,351				

Step Rate Allocation for Residential Customers

		(18)	(19)	(20)	(21) (19) * (20)
	Rate Schedule	Allocation	Annual kWh	Levelized Adj.	Revenues
56	RS	Sales	303,969,401	$0.10417	$31,664,493
57	RS	<= 1,000kWh/mo.	216,022,772	$0.10055	$21,721,826
58	RS	> 1,000 kWh/mo.	87,946,629	$0.11305	$9,942,666
59	RS	Total Sales	303,969,401		$31,664,493

(2) From Gulf Power 2012 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)	$0.18455	$0.06155
61	GS	0.0400	(0.0500)	$0.13975	$0.04975
62	GSD	0.0400	(0.0325)	$0.13530	$0.06280
63	GSLD	0.0600	(0.0300)	$0.15238	$0.06238
64	Interruptible	(0.0150)	-	$0.07738	$0.09238

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FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2017 - DECEMBER 2017
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

FLORIDA DIVISION-CONSOLIDATED

Under-recovery of purchased power costs for the period January 2016 - December 2016. (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 2016.)(Estimated)	$	1,289,892
Portion of 2016 Under-recovery to be collected for the period January 2017 - December 2017	$	1,289,892
Estimated kilowatt hour sales for the months of January 2016 - December 2017 as per estimate filed with the Commission. (Excludes GSLD1 customers)		614,609,517
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2017 - December 2017		0.20987

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SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

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		2,112,568	1,929,429	1,548,325	1,493,250	1,674,869	2,170,114	2,588,823	2,482,169	2,209,800	1,818,781	1,645,904	1,828,999	23,503,028	3
3a	DEMAND & NON FUEL COST OF PUR POWER		2,494,383	2,423,917	2,123,702	2,070,819	2,191,903	2,398,657	2,393,505	2,421,680	2,309,833	2,112,762	2,003,063	2,097,950	27,042,173	3a
3b	QUALIFYING FACILITIES		1,170,781	1,095,984	1,199,795	1,136,202	1,199,795	1,165,216	1,170,781	1,199,795	1,165,216	1,170,781	1,165,141	1,199,795	14,039,282	3b
4	OTHER FUEL RELATED COSTS		27,850	27,850	29,300	27,850	27,850	29,300	27,850	27,850	29,300	27,850	27,850	30,300	341,000	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		5,805,582	5,477,179	4,901,121	4,728,121	5,094,416	5,763,287	6,180,958	6,131,493	5,714,148	5,130,174	4,841,957	5,157,044	64,925,483	5
5a	LESS: TOTAL DEMAND COST RECOVERY		1,967,212	1,875,830	1,634,877	1,602,910	1,686,810	1,833,140	1,782,670	1,817,817	1,733,858	1,568,161	1,502,618	1,611,449	20,617,351	5a
5b	TOTAL OTHER COST TO BE RECOVERED		3,838,370	3,601,350	3,266,245	3,125,211	3,407,607	3,930,147	4,398,289	4,313,677	3,980,291	3,562,013	3,339,340	3,545,595	44,308,132	5b
6	APPORTIONMENT TO GSLD1 CLASS		432,030	504,061	475,263	384,386	423,820	382,151	487,112	393,009	380,962	370,452	434,268	437,077	5,104,591	6
6a	BALANCE TO OTHER CLASSES		3,406,339	3,097,288	2,790,981	2,740,825	2,983,787	3,547,996	3,911,177	3,920,668	3,599,329	3,191,560	2,905,072	3,108,519	39,203,541	6a
6b	SYSTEM KWH SOLD (MWH)		54,857	53,992	47,663	43,596	46,458	54,844	68,365	65,548	61,406	48,291	45,474	47,668	638,162	6b
7	GSLD1 MWH SOLD		2,080	3,230	2,630	1,280	1,890	1,316	3,076	1,513	1,304	1,131	2,047	2,056	23,553	7
7a	BALANCE MWH SOLD OTHER CLASSES		52,777	50,762	45,033	42,316	44,568	53,528	65,289	64,035	60,102	47,160	43,427	45,612	614,609	7a
7b	COST PER KWH SOLD (CENTS/KWH) APPLICABLE TO OTHER CLASSES		6.45421	6.10159	6.19764	6.47704	6.69491	6.6283	5.99056	6.1227	5.9887	6.76752	6.68955	6.81513	6.37861	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)		6.45421	6.10159	6.19764	6.47704	6.69491	6.62830	5.99056	6.12270	5.98870	6.76752	6.68955	6.81513	6.37861	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)	1,289,892	0.20987	0.20987	0.20987	0.20987	0.20987	0.20987	0.20987	0.20987	0.20987	0.20987	0.20987	0.20987	0.20987	12
13	TOTAL		6.66408	6.31146	6.40751	6.68691	6.90478	6.83817	6.20043	6.33257	6.19857	6.97739	6.89942	7.02500	6.58848	13
14	REVENUE TAX FACTOR	0.00072	0.00480	0.00454	0.00461	0.00481	0.00497	0.00492	0.00446	0.00456	0.00446	0.00502	0.00497	0.00506	0.00474	14
15	RECOVERY FACTOR ADJUSTED FOR TAXES		6.66888	6.31600	6.41212	6.69172	6.90975	6.84309	6.20489	6.33713	6.20303	6.98241	6.90439	7.03006	6.59322	15
16	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		6.669	6.316	6.412	6.692	6.91	6.843	6.205	6.337	6.203	6.982	6.904	7.03	6.593	16

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FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

(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 2017	JEA/GULF	MS	41,046,000			41,046,000	5.146829	11.291723	2,112,568
FEBRUARY 2017	JEA/GULF	MS	38,547,000			38,547,000	5.005392	11.365853	1,929,429
MARCH 2017	JEA/GULF	MS	30,107,000			30,107,000	5.142740	12.293907	1,548,325
APRIL 2017	JEA/GULF	MS	28,498,000			28,498,000	5.239842	12.604111	1,493,250
MAY 2017	JEA/GULF	MS	32,802,000			32,802,000	5.105996	11.873122	1,674,869
JUNE 2017	JEA/GULF	MS	43,247,000			43,247,000	5.017953	10.632116	2,170,114
JULY 2017	JEA/GULF	MS	51,896,000			51,896,000	4.988482	9.654265	2,588,823
AUGUST 2017	JEA/GULF	MS	49,837,000			49,837,000	4.980574	9.895656	2,482,169
SEPTEMBER 2017	JEA/GULF	MS	44,261,000			44,261,000	4.992656	10.277518	2,209,800
OCTOBER 2017	JEA/GULF	MS	36,529,000			36,529,000	4.979005	10.839039	1,818,781
NOVEMBER 2017	JEA/GULF	MS	32,156,000			32,156,000	5.118496	11.434309	1,645,904
DECEMBER 2017	JEA/GULF	MS	34,874,000			34,874,000	5.244593	11.347277	1,828,999
TOTAL			463,800,000	0	0	463,800,000	5.067492	10.971583	23,503,028

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FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
PURCHASED POWER
ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

(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 2017	WEST-ROCK/RAYONIER/EIGHT FLAGS		16,467,000			16,467,000	7.109862	7.109862	1,170,781
FEBRUARY 2017	WEST-ROCK/RAYONIER/EIGHT FLAGS		15,098,000			15,098,000	7.259134	7.259134	1,095,984
MARCH 2017	WEST-ROCK/RAYONIER/EIGHT FLAGS		16,467,000			16,467,000	7.286057	7.286057	1,199,795
APRIL 2017	WEST-ROCK/RAYONIER/EIGHT FLAGS		16,011,000			16,011,000	7.096384	7.096384	1,136,202
MAY 2017	WEST-ROCK/RAYONIER/EIGHT FLAGS		16,467,000			16,467,000	7.286057	7.286057	1,199,795
JUNE 2017	WEST-ROCK/RAYONIER/EIGHT FLAGS		16,011,000			16,011,000	7.277597	7.277597	1,165,216
JULY 2017	WEST-ROCK/RAYONIER/EIGHT FLAGS		16,467,000			16,467,000	7.109862	7.109862	1,170,781
AUGUST 2017	WEST-ROCK/RAYONIER/EIGHT FLAGS		16,467,000			16,467,000	7.286057	7.286057	1,199,795
SEPTEMBER 2017	WEST-ROCK/RAYONIER/EIGHT FLAGS		16,011,000			16,011,000	7.277597	7.277597	1,165,216
OCTOBER 2017	WEST-ROCK/RAYONIER/EIGHT FLAGS		16,467,000			16,467,000	7.109862	7.109862	1,170,781
NOVEMBER 2017	WEST-ROCK/RAYONIER/EIGHT FLAGS		16,010,000			16,010,000	7.277583	7.277583	1,165,141
DECEMBER 2017	WEST-ROCK/RAYONIER/EIGHT FLAGS		16,467,000			16,467,000	7.286057	7.286057	1,199,795
TOTAL			194,410,000	0	0	194,410,000	7.221481	7.221481	14,039,282

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FLORIDA PUBLIC UTILITIES COMPANY
FLORIDA DIVISION-CONSOLIDATED
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

	JANUARY 2017	FEBRUARY 2017	MARCH 2017	APRIL 2017	MAY 2017	JUNE 2017	JULY 2017
BASE RATE REVENUES ** $	34.95	34.95	34.95	34.95	34.95	34.95	34.95
FUEL RECOVERY FACTOR CENTS/KWH	10.06	10.06	10.06	10.06	10.06	10.06	10.06
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	100.55	100.55	100.55	100.55	100.55	100.55	100.55
GROSS RECEIPTS TAX	3.47	3.47	3.47	3.47	3.47	3.47	3.47
TOTAL REVENUES *** $	138.97	138.97	138.97	138.97	138.97	138.97	138.97

	AUGUST 2017	SEPTEMBER 2017	OCTOBER 2017	NOVEMBER 2017	DECEMBER 2017	PERIOD TOTAL
BASE RATE REVENUES ** $	34.95	34.95	34.95	34.95	34.95	419.40
FUEL RECOVERY FACTOR CENTS/KWH	10.06	10.06	10.06	10.06	10.06	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	100.55	100.55	100.55	100.55	100.55	1,206.60
GROSS RECEIPTS TAX	3.47	3.47	3.47	3.47	3.47	41.64
TOTAL REVENUES *** $	138.97	138.97	138.97	138.97	138.97	1,667.64

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	14.00
CENTS/KWH	19.60
CONSERVATION FACTOR	1.35
	34.95

*** EXCLUDES FRANCHISE TAXES

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FLORIDA PUBLIC UTILITIES COMPANY
(MC-2)

Florida Public Utilities Company
FPL Interconnect
Calculation of the Actual Revenue Requirements
Projected 2017

Schedule A
Exhibit_____
Michael Cassel (MC-2)
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Item	Beginning Balance	*Projected* Jan	*Projected* Feb	*Projected* Mar	*Projected* Apr	*Projected* May	*Projected* Jun	*Projected* Jul	*Projected* Aug	*Projected* Sep	*Projected* Oct	*Projected* Nov	*Projected* Dec	Year End Total/Balance
Qualified Investment														
Qualified Investment - Interconnect CWIP Activity	$0	$105,855	$105,855	$105,855	$105,855	$105,855	$105,855	$105,855	$105,855	$105,855	$105,855	$105,855	$105,855	$1,270,260
Qualified Investment - Interconnect CWIP Activity to Plant														$0
Qualified Investment - Mains - Current 1010 Activity														$0
Total Qualified Investment - Interconnect 1070 Activity	$919,270	$1,025,125	$1,130,980	$1,236,835	$1,342,690	$1,448,545	$1,554,400	$1,660,255	$1,766,110	$1,871,965	$1,977,820	$2,083,675	$2,189,530	$2,189,530
Total Qualified Investment - Interconnect 1010	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Qualified Investment	$919,270	$1,025,125	$1,130,980	$1,236,835	$1,342,690	$1,448,545	$1,554,400	$1,660,255	$1,766,110	$1,871,965	$1,977,820	$2,083,675	$2,189,530	$2,189,530
Less: Accumulated Depreciation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Book Value	$919,270	$1,025,125	$1,130,980	$1,236,835	$1,342,690	$1,448,545	$1,554,400	$1,660,255	$1,766,110	$1,871,965	$1,977,820	$2,083,675	$2,189,530	$2,189,530
Average Net Qualified Investment		$972,198	$1,078,053	$1,183,908	$1,289,763	$1,395,618	$1,501,473	$1,607,328	$1,713,183	$1,819,038	$1,924,893	$2,030,748	$2,136,603	
Depreciation Rates														
Approved Depreciation Rate														
Return on Average Net Qualified Investment														
Equity - Cost of Capital, inclusive of Income Tax Gross-up		6.4700%	6.4700%	6.4700%	6.4700%	6.4700%	6.4700%	6.4700%	6.4700%	6.4700%	6.4700%	6.4700%	6.4700%	
Debt - Cost of Capital		1.2500%	1.2500%	1.2500%	1.2500%	1.2500%	1.2500%	1.2500%	1.2500%	1.2500%	1.2500%	1.2500%	1.2500%	
Equity Component - inclusive of Income Tax Gross-up		$5,242	$5,813	$6,383	$6,954	$7,525	$8,095	$8,666	$9,237	$9,808	$10,378	$10,949	$11,520	$100,570
Debt Component		$1,013	$1,123	$1,233	$1,344	$1,454	$1,564	$1,674	$1,785	$1,895	$2,005	$2,115	$2,226	$19,431
Return Requirement		$6,255	$6,936	$7,616	$8,298	$8,979	$9,659	$10,340	$11,022	$11,703	$12,383	$13,064	$13,746	$120,001
Investment Expenses														
Depreciation Expense		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Property Taxes	2.00%	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Public Notice Expense & Customer Notice Expense														$0
														$0
														$0
Total Expense		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Revenue Requirements		$6,255	$6,936	$7,616	$8,298	$8,979	$9,659	$10,340	$11,022	$11,703	$12,383	$13,064	$13,746	$120,001
Net Revenue Requirements / (Surplus)		$6,255	$6,936	$7,616	$8,298	$8,979	$9,659	$10,340	$11,022	$11,703	$12,383	$13,064	$13,746	$120,001
Surcharge Revenues Collected Month		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0
Beginning True-Up														$ -
(Over) and Under Recovery for the Month		$ 6,255	$ 6,936	$ 7,616	$ 8,298	$ 8,979	$ 9,659	$ 10,340	$ 11,022	$ 11,703	$ 12,383	$ 13,064	$ 13,746	$ 120,001
Monthly Interest (Expense)/Income		$ 1	$ 3	$ 5	$ 7	$ 10	$ 12	$ 15	$ 18	$ 22	$ 25	$ 29	$ 33	$ 180
Ending (Over) and Under Recovery	$ -	$ 6,256	$ 13,195	$ 20,816	$ 29,121	$ 38,110	$ 47,781	$ 58,136	$ 69,176	$ 80,901	$ 93,309	$ 106,402	$ 120,181	$ 120,181
Beg of Month Annual Interest Rate		0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
End of Month Annual Interest Rate		0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
Average Monthly Interest Rate		0.029%	0.029%	0.029%	0.029%	0.029%	0.029%	0.029%	0.029%	0.029%	0.029%	0.029%	0.029%	

Florida Public Utilities Company

FPL Interconnect
Calculation of the Customer Savings
Projected 2017 - 2025

Prices and Costs for Generation Services ($/MWh)

	2017	2018	2019	2020	2021	2022	2023	2024	2025
JEA Costs	[redacted]								*
FPL	[redacted]								*
Price Differenti	23.15	23.93	16.64	16.26	15.06	14.49	12.56	14.65	11.23

Indicative Net Benefits to Customers ($ 000)

Purchase Quantity Scenario (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025
10 MW	1,324	1,369	952	930	861	829	718	838	642
20 MW	2,649	2,738	1,904	1,861	1,722	1,658	1,437	1,676	1,284

Load Factor, Northeast Division
0.65

* "These indicative prices are based on simulations of the financial costs of generation services, for Florida Power and Light and Jacksonville Electric Authority. The analyses utilize historical data available in the public domain, and resource plans filed before the Florida Public Service Commission. The underlying data are not complete in all dimensions; as a consequence, the analysis includes reasonable judgements and inferences where necessary."

HRBall Testimony Exhibit - Schedule 1

Contract Coal Suppliers	Tons Recieved (1)(2)	
The American Coal Company (Plant Crist)	124,583	
Foresight Coal Sales (Plant Crist)	723,620	
Alpha Coal Sales (Plants Crist and Smith)	602,433	
Peabody Coal Sales - Twentymile Mine (Plant Daniel)	7,400	
Oxbow Carbon & Minerals (Plant Daniel)	60	
TOTAL Contract Coal		1,458,096

Spot Coal Suppliers	Tons Received (1)(2)	
Arch Coal Sales - Black Thunder Mine (Plants Crist and Smith)	153,494	
Argus Coal Sales (Plants Crist and Smith)	57,345	
Glencore LTD (Plants Crist and Smith)	237,792	
Peabody Coal Sales - Twentymile Mine (Plant Daniel)	36,643	
Peabody Coal Sales - Powder River Mine (Daniel)	122,997	
Arch Coal Sales - West Elk Mine (Plant Daniel)	346,368	
Arch Coal Sales - Black Thunder Mine (Plant Daniel)	359,648	
TOTAL Spot Coal		1,314,288

GRAND TOTAL COAL RECEIPTS	**2,772,383**

(1) Excludes Plant Scherer.
(2) Plant Daniel tons represent Gulf's 50% share of receipts.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 39
PARTY: GULF POWER COMPANY – (DIRECT)
DESCRIPTION: H. R. Ball HRB-1

Docket No. 160001-EI
2015 Final True-Up Filing
Exhibit HRB-1, Page 1 of 4

HRBall Testimony Exhibit - Schedule 2

	A	B	C	D	E
1	**Gulf Contract Coal Supplies**				
2			**Received**	**Actual**	**Weighted Avg**
3	**Supplier**	**Plant**	**Quantity (tons)**	**Heating Value**	**Price $/MMBTU)**
4	American Coal Company	Crist	124,583	11858	[redacted]
5	Foresight Coal Sales	Crist	723,620	11771	
6	Alpha Coal Sales	Crist	467,757	12369	
7	**Weighted Average**	**Crist**	**1,315,960**	**11992**	**$3.764**
8					
9	Alpha Coal Sales	Smith	134,676	12348	[redacted]
10	**Weighted Average**	**Smith**	**134,676**	**12348**	**$4.894**
11					
12	Coal Sales Twentymile Coal Co.	Daniel (Gulf 50%)	7,400	11128	[redacted]
13	Oxbow Carbon	Daniel (Gulf 50%)	60	12020	
14	**Weighted Average**	**Daniel (Gulf 50%)**	**7,460**	**11135**	**$5.899**
15					
16	**Gulf Spot Coal Supplies**				
17			**Received**	**Actual**	**Weighted Avg**
18	**Supplier**	**Plant**	**Quantity (tons)**	**Heating Value**	**Price $/MMBTU)**
19	Arch Coal Sales	Crist	52,426	8863	[redacted]
20	Argus Coal Sales	Crist	18,245	11897	
21	Glencore LTD	Crist	167,049	12145	
22	**Weighted Average**	**Crist**	**237,720**	**11402**	**$3.782**
23					
24	Arch Coal Sales	Smith	101068	8906	[redacted]
25	Argus Coal Sales	Smith	39100	11932	
26	Glencore LTD	Smith	70743	11802	
27	**Weighted Average**	**Smith**	**210911**	**10438**	**$3.516**
28					
29	Coal Sales	Daniel (Gulf 50%)	122997	8787	[redacted]
30	Arch Coal Sales	Daniel (Gulf 50%)	249848	11415	
31	Arch Coal Sales	Daniel (Gulf 50%)	299158	8866	
32	Arch Coal Sales	Daniel (Gulf 50%)	96519	11551	
33	Peabody Coal Sales	Daniel (Gulf 50%)	36643	11266	
34	Arch Coal Sales	Daniel (Gulf 50%)	40442	8863	
35	Arch Coal Sales	Daniel (Gulf 50%)	20048	8788	
36	**Weighted Average**	**Daniel (Gulf 50%)**	**865,656**	**9990**	**$3.401**

HRBall Testimony Exhibit - Schedule 3

Gulf Natural Gas Purchase Price Variance
Actual Gas Price vs. Market Gas Price

Gulf Gas Purchase data for Smith 3 and for Central Alabama from the monthly gas invoice.

	Gulf Actual Purchases MMBtu	Gas Purchases Gulf Actual Delivered Cost (Total Dollars)	Monthly Gas Hedge Settlement (Total Dollars)	Gulf Actual Gas Purchases Weighted Average Commodity $/MMBtu	Gulf Actual Gas Storage and Transportation $/MMBtu	Gulf Actual Gas Purchases Delivered Cost $/MMBtu	Gulf Actual Hedged Gas Purchases Delivered Cost $/MMBtu	FGT Zone 3 Weighted Average Market Price Commodity $/MMBtu
Jan-15	5,412,969	$ 19,474,221	$ 4,004,715	$3.13	$0.47	$3.60	$4.34	$3.00
Feb-15	4,478,793	$ 15,090,963	$ 4,645,635	$2.91	$0.46	$3.37	$4.41	$2.85
Mar-15	1,581,584	$ 6,909,071	$ 2,024,810	$3.98	$0.39	$4.37	$5.65	$2.83
Apr-15	3,184,636	$ 12,356,546	$ 3,488,270	$1.91	$1.97	$3.88	$4.98	$2.60
May-15	5,251,786	$ 18,909,844	$ 4,168,464	$2.88	$0.72	$3.60	$4.39	$2.89
Jun-15	4,917,446	$ 17,933,694	$ 4,097,270	$2.95	$0.70	$3.65	$4.48	$2.82
Jul-15	5,970,411	$ 21,348,678	$ 4,129,455	$2.98	$0.60	$3.58	$4.27	$2.85
Aug-15	5,594,834	$ 19,968,355	$ 4,233,885	$2.95	$0.62	$3.57	$4.33	$2.79
Sep-15	5,458,365	$ 18,599,764	$ 4,378,195	$2.76	$0.65	$3.41	$4.21	$2.63
Oct-15	5,184,519	$ 16,458,323	$ 4,009,513	$2.38	$0.79	$3.17	$3.95	$2.31
Nov-15	3,303,705	$ 9,616,942	$ 5,158,051	$2.08	$0.83	$2.91	$4.47	$2.09
Dec-15	4,886,249	$ 12,149,901	$ 6,234,099	$2.05	$0.44	$2.49	$3.76	$1.89
TOTAL	**55,225,297**	**$ 188,816,302**	**$ 50,572,362**	**$2.80**	**$0.62**	**$3.42**	**$4.33**	**$2.63**

HRBall Testimony Exhibit - Schedule 4

2014 Natural Gas Burn Cost Variance and Hedging Effectiveness

Hedging Settlement Cost from Schedule A-1

NOTE: Gas Burn Cost and Gas MMBTU's burned is billed amount for Gulf owned gas fired generation and purchase power agreement (PPA) generating units for which Gulf supplies the fuel.

	Gas Burn for Generation MMBtu	Gas Cost for Generation Actual Cost	Gulf Hedge Settlement Total $	Gas Cost for Generation Hedged Cost	Gas Cost for Generation Actual Cost $/MMBtu	Gas Cost for Generation Hedged Cost $/MMBtu
Jan-15	**5,721,570**	$ 21,485,149	$ 4,004,715	$ 25,489,864	$ 3.76	$ 4.46
Feb-15	**5,076,430**	$ 17,694,283	$ 4,645,635	$ 22,339,918	$ 3.49	$ 4.40
Mar-15	**1,613,482**	$ 5,632,536	$ 2,024,810	$ 7,657,346	$ 3.49	$ 4.75
Apr-15	**3,016,594**	$ 12,050,622	$ 3,488,270	$ 15,538,892	$ 3.99	$ 5.15
May-15	**4,925,408**	$ 18,431,600	$ 4,168,464	$ 22,600,064	$ 3.74	$ 4.59
Jun-15	**4,989,344**	$ 18,314,885	$ 4,097,270	$ 22,412,155	$ 3.67	$ 4.49
Jul-15	**6,118,365**	$ 22,008,988	$ 4,129,455	$ 26,138,443	$ 3.60	$ 4.27
Aug-15	**5,720,710**	$ 20,496,183	$ 4,233,885	$ 24,730,068	$ 3.58	$ 4.32
Sep-15	**5,508,147**	$ 18,984,693	$ 4,378,195	$ 23,362,888	$ 3.45	$ 4.24
Oct-15	**5,165,644**	$ 16,720,635	$ 4,009,513	$ 20,730,148	$ 3.24	$ 4.01
Nov-15	**3,249,852**	$ 9,752,334	$ 5,158,051	$ 14,910,385	$ 3.00	$ 4.59
Dec-15	**4,937,366**	$ 12,881,657	$ 6,234,099	$ 19,115,756	$ 2.61	$ 3.87
TOTAL	**56,042,912**	**$ 194,453,565**	**$ 50,572,362**	**$ 245,025,927**		
Weighted Average Price					**$ 3.47**	**$ 4.37**
Variance					**0.14**	**0.11**
Standard Deviation					**0.37**	**0.33**

Schedule 1

GULF POWER COMPANY
PROJECTED VS. ACTUAL FUEL COST OF SYSTEM NET GENERATION

Cents / KWH Fuel Cost

Period Ending	Projected[1]	Actual[1]	% Difference[1]
December 2006	2.9215	3.0902	5.77
December 2007	3.3156	3.2959	(0.59)
December 2008	3.7567	4.2044	11.92
December 2009	4.3406	3.8661	(10.93)
December 2010	4.8818	4.9626	1.66
December 2011	4.7917	4.7259	1.37
December 2012	4.2617	3.9806	(6.60)
December 2013	4.1654	4.2198	1.31
December 2014	4.0342	4.0624	0.70
December 2015	3.5856	3.4415	4.02
December 2016	3.1072[2]		
December 2017	2.9344[3]		

(1) Line No. 1 from FPSC Schedule A-1, December, Period To Date
(2) Line No. 1 from FPSC Schedule E-1B-1, 2016 Actual / Estimated True-Up
(3) Line No. 1 from FPSC Schedule E-1, 2017 Projection Filing

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 40
PARTY: GULF POWER COMPANY – (DIRECT)
DESCRIPTION: H. R. Ball HRB-2

	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	Volume	Dollar Amount
1	JPMORG	6448	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	10000	
2	JPMORG	6532	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	20000	
3	JPMORG	6551	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	10000	
4	JPMORG	6753	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	10000	
5	JPMORG	6769	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	10000	
6	JPMORG	6883	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	10000	
7	JPMORG	6923	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	10000	
8	JPMORG	7116	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	20000	
9	BARCLAY	7144	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	20000	
10	JPMORG	7152	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	20000	
11	JPMORG	7232	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	20000	
12	BMO	7344	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	20000	
13	CIBC	7362	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	20000	
14	CITIGR	7383	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	20000	
15	BARCLAY	7446	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	30000	
16	BMO	7469	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	20000	
17	JPMORG	7553	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	20000	
18	BARCLAY	7570	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	20000	
19	JPMORG	7600	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	20000	
20	BARCLAY	7623	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	30000	
21	JPMORG	7671	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	30000	
22	MERRIL	7690	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	30000	
23	SHELLTRADE	7709	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
24	SHELLTRADE	7716	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	50000	
25	MERRIL	7756	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
26	BMO	7821	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
27	BP	7829	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
28	CITIGR	7844	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
29	SHELLTRADE	7859	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	50000	
30	BMO	7873	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	50000	
31	BMO	7892	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	60000	
32	BARCLAY	7924	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	30000	
33	BNPP ET	7936	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	30000	
34	MERRIL	7999	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	20000	
35	JPMORG	8009	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	30000	
36	BARCLAY	8038	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	30000	
37	MERRIL	8086	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	50000	
38	SHELLTRADE	8114	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
39	CITIGR	8124	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
40	BARCLAY	8145	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
41	CITIGR	8152	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
42	BARCLAY	8212	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	30000	
43	BMO	8247	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
44	SHELLTRADE	8271	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	10000	
45	CITIGR	8272	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	10000	
46	MERRIL	8309	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
47	BARCLAY	8317	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
48	JPMORG	8353	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
49	CITIGR	8362	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
50	BMO	8383	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
51	BMO	8400	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
52	BMO	8409	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
53	BARCLAY	8450	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
54	CARGILL	8468	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	50000	
55	MERRIL	8490	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	50000	
56	BP	8506	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	60000	
57	CARGILL	8525	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
58	CITIGR	8538	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
59	BP	8575	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
60	BARCLAY	8584	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	70000	
61	BNPP	8599	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	50000	
62	SHELLTRADE	8636	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	50000	
63	CARGILL	8651	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	50000	
64	CARGILL	8679	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
65	BNPP	8712	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
66	BARCLAY	8726	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
67	BNPP	8739	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	50000	
68	MORGAN	8748	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	50000	
69	SHELLTRADE	8757	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	50000	
70	MERRIL	8765	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	30000	
71	CITIGR	8860	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
72	MITSUI	8878	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
73	CITIGR	8916	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	50000	
74	CIBC	8986	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
75	JPMORG	9041	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	150000	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 41
PARTY: GULF POWER COMPANY – (DIRECT)
DESCRIPTION: H. R. Ball HRB-3

	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	Volume	Dollar Amount
76	MERRIL	9054	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	110000	
77	MITSUI	9105	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	50000	
78	JPMORG	9106	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	40000	
79	CITIGR	9136	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	60000	
80	MERRIL	9788	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	350000	
81	MERRIL	9789	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	350000	
82	CIBC	9790	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	350000	
83	CIBC	9791	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	350000	
84	BNPP	9792	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	620000	
85	BNPP	9793	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	620000	
86	BP	9794	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	310000	
87	BP	9795	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	310000	
88	MITSUI	9796	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	310000	
89	MITSUI	9797	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	310000	
90	SHELLTRADE	9798	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	310000	
91	SHELLTRADE	9799	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	310000	
92	MACQUARIE	9800	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	360000	
93	MACQUARIE	9801	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	360000	
94	JPMORG	9803	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	360000	
95	JPMORG	9804	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	360000	
96	BARCLAY	9812	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	110000	
97	BNPP	9813	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	360000	
98	BMO	9817	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	110000	
99	SHELLTRADE	9820	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	110000	
100	BMO	9821	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	110000	
101	MITSUI	9823	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	330000	
102	SCOTIA	9825	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	120000	
103	MITSUI	9826	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	120000	
104	SHELLTRADE	9828	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	120000	
105	CIBC	9829	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	120000	
106	JPMORG	9830	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	360000	
107	SCOTIA	9831	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	120000	
108	MERRIL	9832	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	120000	
109	BMO	9835	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	120000	
110	MITSUI	9840	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	120000	
111	BP	9842	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	360000	
112	CIBC	9846	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	120000	
113	SHELLTRADE	9851	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	120000	
114	MERRIL	9854	Swap	Nymex LD HH		Fixed		Nymex	Aug-15	130000	
115	BARCLAY	9858	Swap	Fixed		Nymex LD HH		Nymex	Aug-15	210000	
116	**TOTAL**										**$ 4,233,885**

	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	Volume	Dollar Amount
1	JPMORG	6448	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	10000	
2	JPMORG	6532	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	20000	
3	JPMORG	6551	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	10000	
4	JPMORG	6753	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	10000	
5	JPMORG	6769	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	10000	
6	JPMORG	6883	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	10000	
7	JPMORG	6923	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	10000	
8	JPMORG	7116	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	20000	
9	BARCLAY	7144	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	20000	
10	JPMORG	7152	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	20000	
11	JPMORG	7232	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	20000	
12	BMO	7344	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	20000	
13	CIBC	7362	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	20000	
14	CITIGR	7383	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	20000	
15	BARCLAY	7446	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	30000	
16	BMO	7469	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	20000	
17	JPMORG	7553	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	20000	
18	BARCLAY	7570	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	20000	
19	JPMORG	7600	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	20000	
20	BARCLAY	7623	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	30000	
21	JPMORG	7671	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	30000	
22	MERRIL	7690	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	30000	
23	SHELLTRADE	7709	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	30000	
24	SHELLTRADE	7716	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	30000	
25	MERRIL	7756	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	20000	
26	BMO	7821	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	30000	
27	BP	7829	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	30000	
28	SHELLTRADE	7859	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	30000	
29	BMO	7873	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	30000	
30	BMO	7892	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	50000	
31	BARCLAY	7924	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	30000	
32	BNPP ET	7936	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	30000	
33	MERRIL	7999	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	20000	
34	JPMORG	8009	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	30000	
35	BARCLAY	8038	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	30000	
36	MERRIL	8086	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	30000	
37	SHELLTRADE	8114	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	
38	CITIGR	8124	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	
39	BARCLAY	8145	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	
40	CITIGR	8152	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	
41	BARCLAY	8212	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	50000	
42	BMO	8247	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	
43	SHELLTRADE	8271	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	10000	
44	CITIGR	8272	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	10000	
45	MERRIL	8309	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	
46	BARCLAY	8317	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	
47	JPMORG	8353	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	
48	CITIGR	8362	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	
49	BMO	8383	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	
50	BMO	8400	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	
51	BMO	8409	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	
52	BARCLAY	8450	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	
53	CARGILL	8468	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	50000	
54	MERRIL	8490	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	50000	
55	BP	8506	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	60000	
56	CARGILL	8525	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	
57	CITIGR	8538	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	60000	
58	BP	8575	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	
59	BARCLAY	8584	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	70000	
60	BNPP	8599	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	50000	
61	SHELLTRADE	8636	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	50000	
62	CARGILL	8651	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	50000	
63	CARGILL	8679	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	
64	BNPP	8712	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	
65	BARCLAY	8726	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	
66	BNPP	8739	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	50000	
67	MORGAN	8748	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	50000	
68	SHELLTRADE	8757	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	50000	
69	MERRIL	8765	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	30000	
70	CITIGR	8860	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	
71	CITIGR	8916	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	50000	
72	CIBC	8986	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	
73	JPMORG	9041	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	150000	
74	MERRIL	9054	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	110000	
75	MITSUI	9105	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	50000	
76	JPMORG	9106	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	40000	

	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	Volume	Dollar Amount
77	CITIGR	9136	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	60000	
78	MITSUI	9855	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	460000	
79	MITSUI	9856	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	460000	
80	SHELLTRADE	9859	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	470000	
81	SHELLTRADE	9860	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	470000	
82	BARCLAY	9861	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	460000	
83	BARCLAY	9862	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	460000	
84	JPMORG	9864	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	470000	
85	JPMORG	9865	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	470000	
86	SCOTIA	9866	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	460000	
87	SCOTIA	9867	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	460000	
88	CIBC	9868	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	470000	
89	CIBC	9869	Swap	Fixed		Nymex LD HH		Nymex	Sep-15	470000	
90	BNPP	9870	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	100000	
91	MITSUI	9871	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	100000	
92	SHELLTRADE	9872	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	100000	
93	BMO	9873	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	100000	
94	JPMORG	9874	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	400000	
95	CIBC	9875	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	100000	
96	MACQUARIE	9876	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	100000	
97	MITSUI	9877	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	100000	
98	BNPP	9880	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	280000	
99	SCOTIA	9881	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	90000	
100	CIBC	9882	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	90000	
101	JPMORG	9883	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	90000	
102	MITSUI	9886	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	90000	
103	BMO	9887	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	290000	
104	CIBC	9902	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	100000	
105	SHELLTRADE	9905	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	90000	
106	SCOTIA	9909	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	100000	
107	MACQUARIE	9912	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	80000	
108	MITSUI	9915	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	300000	
109	BARCLAY	9919	Swap	Nymex LD HH		Fixed		Nymex	Sep-15	90000	
110	**TOTAL**										**$ 4,378,195**

	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	Volume	Dollar Amount
1	JPMORG	6448	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	10000	
2	JPMORG	6532	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	20000	
3	JPMORG	6551	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	10000	
4	JPMORG	6753	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	10000	
5	JPMORG	6769	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	10000	
6	JPMORG	6883	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	10000	
7	JPMORG	6923	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	10000	
8	JPMORG	7116	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	20000	
9	BARCLAY	7144	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	20000	
10	JPMORG	7152	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	20000	
11	JPMORG	7232	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	20000	
12	BMO	7344	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	20000	
13	CIBC	7362	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	20000	
14	CITIGR	7383	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	20000	
15	BARCLAY	7446	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	20000	
16	BMO	7469	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	20000	
17	JPMORG	7553	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	20000	
18	BARCLAY	7570	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	20000	
19	JPMORG	7600	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	20000	
20	BARCLAY	7623	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	30000	
21	JPMORG	7671	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	30000	
22	MERRIL	7690	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	30000	
23	MERRIL	7756	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	20000	
24	BMO	7873	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	10000	
25	BMO	7892	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	20000	
26	BARCLAY	7924	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	30000	
27	BNPP ET	7936	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	30000	
28	MERRIL	7999	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	20000	
29	JPMORG	8009	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	30000	
30	BARCLAY	8038	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	30000	
31	MERRIL	8086	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	20000	
32	SHELLTRADE	8114	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	40000	
33	CITIGR	8124	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	40000	
34	BARCLAY	8145	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	40000	
35	CITIGR	8152	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	40000	
36	BARCLAY	8212	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	20000	
37	BMO	8247	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	40000	
38	SHELLTRADE	8271	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	10000	
39	CITIGR	8272	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	10000	
40	MERRIL	8309	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	40000	
41	BARCLAY	8317	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	40000	
42	JPMORG	8353	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	40000	
43	CITIGR	8362	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	40000	
44	BMO	8409	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	20000	
45	CARGILL	8468	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	50000	
46	MERRIL	8490	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	50000	
47	BP	8506	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	60000	
48	CARGILL	8525	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	40000	
49	CITIGR	8538	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	40000	
50	BP	8575	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	40000	
51	BARCLAY	8584	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	70000	
52	BNPP	8599	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	50000	
53	SHELLTRADE	8636	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	20000	
54	CARGILL	8651	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	50000	
55	CARGILL	8679	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	40000	
56	BNPP	8712	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	40000	
57	MORGAN	8748	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	50000	
58	SHELLTRADE	8757	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	50000	
59	MERRIL	8765	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	50000	
60	CITIGR	8860	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	40000	
61	CITIGR	8916	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	50000	
62	CIBC	8986	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	40000	
63	JPMORG	9041	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	150000	
64	MITSUI	9105	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	50000	
65	JPMORG	9106	Swap	Fixed		Nymex LD HH		Nymex	Oct-15	40000	
66	BNPP	9884	Swap	Nymex LD HH		GD HH		Gas Daily	Oct-15	620000	
67	MITSUI	9885	Swap	Nymex LD HH		GD HH		Gas Daily	Oct-15	620000	
68	BNPP	9906	Swap	Nymex LD HH		GD HH		Gas Daily	Oct-15	310000	
69	MITSUI	9907	Swap	Nymex LD HH		GD HH		Gas Daily	Oct-15	250000	
70	SHELLTRADE	9913	Swap	Nymex LD HH		GD HH		Gas Daily	Oct-15	310000	
71	**TOTAL**										**$ 4,009,513**

	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	Volume	Dollar Amount
1	JPMORG	6448	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	10000	
2	JPMORG	6532	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	20000	
3	JPMORG	6551	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	10000	
4	JPMORG	6753	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	10000	
5	JPMORG	6769	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	10000	
6	JPMORG	6883	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	10000	
7	JPMORG	6923	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	10000	
8	JPMORG	7116	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	20000	
9	BARCLAY	7144	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	20000	
10	JPMORG	7152	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	20000	
11	JPMORG	7232	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	20000	
12	BMO	7344	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	20000	
13	CIBC	7362	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	20000	
14	CITIGR	7383	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	20000	
15	BARCLAY	7446	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	20000	
16	BMO	7469	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	20000	
17	JPMORG	7553	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	20000	
18	BARCLAY	7570	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	20000	
19	JPMORG	7600	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	20000	
20	BARCLAY	7623	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	30000	
21	JPMORG	7671	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	30000	
22	MERRIL	7690	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	30000	
23	SHELLTRADE	7709	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	30000	
24	SHELLTRADE	7716	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	30000	
25	MERRIL	7756	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	20000	
26	BMO	7821	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	30000	
27	BP	7829	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	30000	
28	SHELLTRADE	7859	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	30000	
29	BMO	7873	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	30000	
30	BMO	7892	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	50000	
31	BARCLAY	7924	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	30000	
32	BNPP ET	7936	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	30000	
33	MERRIL	7999	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	20000	
34	JPMORG	8009	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	30000	
35	BARCLAY	8038	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	30000	
36	MERRIL	8086	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	20000	
37	SHELLTRADE	8114	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	40000	
38	CITIGR	8124	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	40000	
39	BARCLAY	8145	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	40000	
40	CITIGR	8152	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	40000	
41	BARCLAY	8212	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	20000	
42	BMO	8247	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	40000	
43	SHELLTRADE	8271	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	10000	
44	CITIGR	8272	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	10000	
45	MERRIL	8309	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	40000	
46	BARCLAY	8317	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	40000	
47	JPMORG	8353	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	40000	
48	CITIGR	8362	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	40000	
49	BMO	8409	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	20000	
50	CARGILL	8468	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	50000	
51	MERRIL	8490	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	50000	
52	BP	8506	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	60000	
53	CARGILL	8525	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	40000	
54	CITIGR	8538	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	40000	
55	BP	8575	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	40000	
56	BARCLAY	8584	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	70000	
57	BNPP	8599	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	50000	
58	SHELLTRADE	8636	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	20000	
59	CARGILL	8651	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	50000	
60	CARGILL	8679	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	40000	
61	BNPP	8712	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	40000	
62	MORGAN	8748	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	50000	
63	SHELLTRADE	8757	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	50000	
64	MERRIL	8765	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	50000	
65	CITIGR	8860	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	40000	
66	CITIGR	8916	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	50000	
67	CIBC	8986	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	40000	
68	JPMORG	9041	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	150000	
69	MERRIL	9054	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	110000	
70	MITSUI	9105	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	50000	
71	JPMORG	9106	Swap	Fixed		Nymex LD HH		Nymex	Nov-15	40000	
72	MITSUI	9933	Swap	Nymex LD HH		GD HH		Gas Daily	Nov-15	600000	
73	JPMORG	9934	Swap	Nymex LD HH		GD HH		Gas Daily	Nov-15	600000	
74	BNPP	9935	Swap	Nymex LD HH		GD HH		Gas Daily	Nov-15	600000	
75	MITSUI	9936	Swap	Nymex LD HH		GD HH		Gas Daily	Nov-15	600000	
76	SHELLTRADE	9938	Swap	Nymex LD HH		GD HH		Gas Daily	Nov-15	20000	
77	**TOTAL**										**$ 5,158,051**

	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	Volume	Dollar Amount
1	JPMORG	6448	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	10000	
2	JPMORG	6532	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	20000	
3	JPMORG	6551	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	10000	
4	JPMORG	6753	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	10000	
5	JPMORG	6769	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	10000	
6	JPMORG	6883	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	10000	
7	JPMORG	6923	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	10000	
8	JPMORG	7116	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	20000	
9	BARCLAY	7144	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	20000	
10	JPMORG	7152	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	20000	
11	JPMORG	7232	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	20000	
12	BMO	7344	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	20000	
13	CIBC	7362	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	20000	
14	CITIGR	7383	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	20000	
15	BARCLAY	7446	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	20000	
16	BMO	7469	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	20000	
17	JPMORG	7553	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	20000	
18	BARCLAY	7570	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	20000	
19	JPMORG	7600	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	20000	
20	BARCLAY	7623	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	30000	
21	JPMORG	7671	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	30000	
22	MERRIL	7690	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	30000	
23	SHELLTRADE	7709	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	30000	
24	SHELLTRADE	7716	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	30000	
25	MERRIL	7756	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	20000	
26	BMO	7821	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	30000	
27	BP	7829	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	30000	
28	SHELLTRADE	7859	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	30000	
29	BMO	7873	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	30000	
30	BMO	7892	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	50000	
31	BARCLAY	7924	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	30000	
32	BNPP ET	7936	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	30000	
33	MERRIL	7999	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	20000	
34	JPMORG	8009	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	30000	
35	BARCLAY	8038	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	30000	
36	MERRIL	8086	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	30000	
37	SHELLTRADE	8114	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	40000	
38	CITIGR	8124	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	40000	
39	BARCLAY	8145	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	40000	
40	CITIGR	8152	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	40000	
41	BARCLAY	8212	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	50000	
42	BMO	8247	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	40000	
43	SHELLTRADE	8271	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	10000	
44	CITIGR	8272	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	10000	
45	MERRIL	8309	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	40000	
46	BARCLAY	8317	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	40000	
47	JPMORG	8353	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	40000	
48	CITIGR	8362	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	40000	
49	BMO	8409	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	30000	
50	CARGILL	8468	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	50000	
51	MERRIL	8490	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	80000	
52	BP	8506	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	60000	
53	CARGILL	8525	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	40000	
54	CITIGR	8538	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	60000	
55	BP	8575	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	40000	
56	BARCLAY	8584	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	70000	
57	BNPP	8599	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	50000	
58	SHELLTRADE	8636	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	80000	
59	CARGILL	8651	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	50000	
60	CARGILL	8679	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	40000	
61	BNPP	8712	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	40000	
62	MORGAN	8748	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	50000	
63	SHELLTRADE	8757	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	50000	
64	MERRIL	8765	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	50000	
65	CITIGR	8860	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	40000	
66	CITIGR	8887	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	50000	
67	CITIGR	8916	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	50000	
68	CIBC	8986	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	40000	
69	JPMORG	9041	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	150000	

	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	Volume	Dollar Amount
70	MERRIL	9054	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	110000	
71	MITSUI	9105	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	50000	
72	JPMORG	9106	Swap	Fixed		Nymex LD HH		Nymex	Dec-15	40000	
73	MITSUI	9943	Swap	Nymex LD HH		GD HH		Gas Daily	Dec-15	620000	
74	BNPP	9944	Swap	Nymex LD HH		GD HH		Gas Daily	Dec-15	620000	
75	JPMORG	9945	Swap	Nymex LD HH		GD HH		Gas Daily	Dec-15	930000	
76	MITSUI	9946	Swap	Nymex LD HH		GD HH		Gas Daily	Dec-15	310000	
77	BNPP	9947	Swap	Nymex LD HH		GD HH		Gas Daily	Dec-15	310000	
78	**TOTAL**										**$ 6,234,099**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 42
PARTY: GULF POWER COMPANY – (DIRECT)
DESCRIPTION: H. R. Ball HRB-4

Docket No. 160001-EI
January - July 2016 Hedging Report
GULF POWER COMPANY

	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	Volume	Dollar Amount
1	BARCLAY	9963	Swap	Nymex LD HH		GD HH		Nymex	Jan-16	620,000	
2	JPMORG	9964	Swap	Nymex LD HH		GD HH		Nymex	Jan-16	290,000	
3	MITSUI	9960	Swap	Nymex LD HH		GD HH		Nymex	Jan-16	620,000	
4	BP	9961	Swap	Nymex LD HH		GD HH		Nymex	Jan-16	620,000	
5	BNPP	9962	Swap	Nymex LD HH		GD HH		Nymex	Jan-16	310,000	
6	BARCLAY	7483	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	20,000	
7	BARCLAY	7619	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	10,000	
8	BARCLAY	7692	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	10,000	
9	BARCLAY	7713	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	10,000	
10	BARCLAY	7937	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	30,000	
11	BARCLAY	7998	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	20,000	
12	BARCLAY	8010	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	20,000	
13	BARCLAY	8072	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	20,000	
14	BARCLAY	9844	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	60,000	
15	CIBC	9098	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	55,000	
16	CIBC	9428	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
17	CIBC	9949	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	20,000	
18	JPMORG	7552	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	20,000	
19	JPMORG	7815	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	30,000	
20	JPMORG	7893	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
21	JPMORG	7926	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	30,000	
22	JPMORG	8033	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	20,000	
23	JPMORG	8085	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	20,000	
24	JPMORG	8347	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	50,000	
25	JPMORG	8470	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
26	JPMORG	8549	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	60,000	
27	JPMORG	8583	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	70,000	
28	JPMORG	8857	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	30,000	
29	JPMORG	9040	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	125,000	
30	JPMORG	9287	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	30,000	
31	JPMORG	9356	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
32	JPMORG	9853	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	60,000	
33	JPMORG	9955	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	150,000	
34	JPMORG	9956	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
35	CITIGR	8495	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	50,000	
36	CARGILL	8949	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
37	CARGILL	9242	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
38	MERRIL	7679	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
39	MERRIL	8213	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	30,000	
40	MERRIL	8358	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	30,000	
41	MERRIL	8410	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
42	MERRIL	8601	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	50,000	
43	MERRIL	8742	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
44	MERRIL	8766	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	30,000	
45	MERRIL	9097	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	70,000	
46	MERRIL	9958	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	110,000	
47	CITIGR	7571	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	10,000	
48	CITIGR	8250	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
49	CITIGR	8523	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	50,000	
50	CITIGR	8714	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
51	CITIGR	8753	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
52	CITIGR	8783	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	20,000	
53	CITIGR	9216	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	60,000	
54	CITIGR	9256	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
55	SHELLTRADE	7827	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	30,000	
56	SHELLTRADE	8115	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	30,000	
57	SHELLTRADE	8984	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
58	BNPP ET	7598	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	10,000	
59	BNPP ET	7673	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	10,000	
60	BNPP ET	7684	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	20,000	
61	BNPP ET	7711	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	30,000	
62	BNPP ET	8043	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	20,000	
63	BNPP ET	8146	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
64	BMO	9487	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
65	BNPP	8573	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	50,000	
66	BNPP	8646	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
67	BNPP	8818	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	20,000	
68	BNPP	9538	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
69	MACQUARIE	9316	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	50,000	
70	MACQUARIE	9573	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
71	MITSUI	9833	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	60,000	
72	MITSUI	9903	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	60,000	
73	MITSUI	9923	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	60,000	

	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	Volume	Dollar Amount
74	MITSUI	9928	Swap	Fixed	[redacted]	Nymex LD HH	[redacted]	Nymex	Jan-16	30,000	[redacted]
75	MITSUI	9965	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	50,000	
76	BARCLAY	9844	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	60,000	
77	CIBC	9428	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
78	JPMORG	9853	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	60,000	
79	MITSUI	9833	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	60,000	
80	MITSUI	9903	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	60,000	
81	MITSUI	9923	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	60,000	
82	CARGILL	8949	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
83	BMO	9487	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
84	BNPP	9538	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
85	MACQUARIE	9573	Swap	Fixed		Nymex LD HH		Nymex	Jan-16	40,000	
86	**TOTAL**										**$ 5,195,191**

	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	Volume	Dollar Amount
1	BARCLAY	9973	Swap	Nymex LD HH		GD HH		Nymex	Feb-16	140,000	
2	JPMORG	9971	Swap	Nymex LD HH		GD HH		Nymex	Feb-16	580,000	
3	MITSUI	9970	Swap	Nymex LD HH		GD HH		Nymex	Feb-16	290,000	
4	SHELLTRADE	9969	Swap	Nymex LD HH		GD HH		Nymex	Feb-16	290,000	
5	BNPP	9972	Swap	Nymex LD HH		GD HH		Nymex	Feb-16	1,160,000	
6	BARCLAY	7483	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	20,000	
7	BARCLAY	7619	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	10,000	
8	BARCLAY	7692	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	10,000	
9	BARCLAY	7713	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	10,000	
10	BARCLAY	7937	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	30,000	
11	BARCLAY	7998	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	20,000	
12	BARCLAY	8010	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	20,000	
13	BARCLAY	8072	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	20,000	
14	CIBC	9098	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	55,000	
15	CIBC	9949	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	20,000	
16	JPMORG	7552	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	20,000	
17	JPMORG	7815	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	30,000	
18	JPMORG	7893	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	40,000	
19	JPMORG	7926	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	30,000	
20	JPMORG	8033	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	20,000	
21	JPMORG	8085	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	20,000	
22	JPMORG	8347	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	50,000	
23	JPMORG	8470	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	40,000	
24	JPMORG	8549	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	60,000	
25	JPMORG	8583	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	70,000	
26	JPMORG	8857	Swap	Fixed		Nymex LD HH		Nymex	Feb-18	30,000	
27	JPMORG	9040	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	125,000	
28	JPMORG	9287	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	30,000	
29	JPMORG	9356	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	40,000	
30	JPMORG	9955	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	150,000	
31	JPMORG	9956	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	40,000	
32	MITSUI	9928	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	30,000	
33	MITSUI	9965	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	50,000	
34	CITIGR	8495	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	50,000	
35	CARGILL	9242	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	40,000	
36	MERRIL	7879	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	40,000	
37	MERRIL	8213	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	30,000	
38	MERRIL	8339	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	50,000	
39	MERRIL	8358	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	30,000	
40	MERRIL	8410	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	40,000	
41	MERRIL	8601	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	50,000	
42	MERRIL	8742	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	40,000	
43	MERRIL	8766	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	30,000	
44	MERRIL	9097	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	70,000	
45	MERRIL	9958	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	110,000	
46	CITIGR	7571	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	10,000	
47	CITIGR	8250	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	40,000	
48	CITIGR	8320	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	50,000	
49	CITIGR	8523	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	50,000	
50	CITIGR	8714	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	40,000	
51	CITIGR	8753	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	40,000	
52	CITIGR	8783	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	20,000	
53	CITIGR	9216	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	60,000	
54	CITIGR	9256	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	40,000	
55	SHELLTRADE	7827	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	30,000	
56	SHELLTRADE	8115	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	30,000	
57	SHELLTRADE	6984	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	40,000	
58	BNPP ET	7598	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	10,000	
59	BNPP ET	7673	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	10,000	
60	BNPP ET	7684	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	20,000	
61	BNPP ET	7711	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	30,000	
62	BNPP ET	8043	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	20,000	
63	BNPP ET	8146	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	40,000	
64	BNPP	8306	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	50,000	
65	BNPP	8573	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	50,000	
66	BNPP	8646	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	40,000	
67	BNPP	8818	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	20,000	
68	MACQUARIE	9316	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	50,000	
69	BARCLAY	9844	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	60,000	
70	CIBC	9428	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	40,000	
71	JPMORG	9853	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	60,000	

	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	Volume	Dollar Amount
72	MITSUI	9833	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	60,000	
73	MITSUI	9903	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	60,000	
74	MITSUI	9923	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	60,000	
75	CARGILL	8949	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	40,000	
76	BMO	9487	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	40,000	
77	BNPP	9538	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	40,000	
78	MACQUARIE	9573	Swap	Fixed		Nymex LD HH		Nymex	Feb-16	40,000	
79	**TOTAL**										**$ 6,107,019**

	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	Volume	Dollar Amount
1	BARCLAY	10025	Swap	Nymex LD HH		GD HH		Nymex	Mar-16	1,550,000	
2	JPMORG	10024	Swap	Nymex LD HH		GD HH		Nymex	Mar-16	1,240,000	
3	MITSUI	10026	Swap	Nymex LD HH		GD HH		Nymex	Mar-16	160,000	
4	BARCLAY	7483	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	20,000	
5	BARCLAY	7619	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	10,000	
6	BARCLAY	7692	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	10,000	
7	BARCLAY	7713	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	10,000	
8	BARCLAY	7937	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	30,000	
9	BARCLAY	7998	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	20,000	
10	BARCLAY	8010	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	20,000	
11	BARCLAY	8072	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	20,000	
12	CIBC	9098	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	55,000	
13	CIBC	9949	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	20,000	
14	JPMORG	7552	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	20,000	
15	JPMORG	7815	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	30,000	
16	JPMORG	7893	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	40,000	
17	JPMORG	7926	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	30,000	
18	JPMORG	8033	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	20,000	
19	JPMORG	8085	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	20,000	
20	JPMORG	8347	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	50,000	
21	JPMORG	8384	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	40,000	
22	JPMORG	8453	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	40,000	
23	JPMORG	8470	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	40,000	
24	JPMORG	8549	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	60,000	
25	JPMORG	8583	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	70,000	
26	JPMORG	8857	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	30,000	
27	JPMORG	9040	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	125,000	
28	JPMORG	9287	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	30,000	
29	JPMORG	9356	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	40,000	
30	JPMORG	9955	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	150,000	
31	JPMORG	9956	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	40,000	
32	MITSUI	9928	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	30,000	
33	MITSUI	9965	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	50,000	
34	CITIGR	8495	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	50,000	
35	CARGILL	8396	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	40,000	
36	CARGILL	9242	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	40,000	
37	MERRIL	7879	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	40,000	
38	MERRIL	8213	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	30,000	
39	MERRIL	8339	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	50,000	
40	MERRIL	8358	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	30,000	
41	MERRIL	8410	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	40,000	
42	MERRIL	8601	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	50,000	
43	MERRIL	8766	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	60,000	
44	MERRIL	9097	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	70,000	
45	MERRIL	9958	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	110,000	
46	CITIGR	7571	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	10,000	
47	CITIGR	8250	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	40,000	
48	CITIGR	8320	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	50,000	
49	CITIGR	8523	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	50,000	
50	CITIGR	8714	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	40,000	
51	CITIGR	9216	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	60,000	
52	CITIGR	9256	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	40,000	
53	SHELLTRADE	7827	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	30,000	
54	SHELLTRADE	8115	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	30,000	
55	BNPP ET	7598	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	10,000	
56	BNPP ET	7673	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	10,000	
57	BNPP ET	7684	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	20,000	
58	BNPP ET	7711	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	30,000	
59	BNPP ET	8043	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	20,000	
60	BNPP ET	8146	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	40,000	
61	BNPP	8306	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	50,000	
62	BNPP	8573	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	50,000	
63	BNPP	8646	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	40,000	
64	MACQUARIE	9316	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	50,000	
65	BARCLAY	9844	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	60,000	
66	CIBC	9428	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	40,000	
67	JPMORG	9853	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	60,000	
68	MITSUI	9833	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	60,000	
69	MITSUI	9903	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	60,000	
70	MITSUI	9923	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	60,000	
71	MERRIL	9236	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	40,000	
72	BMO	9487	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	40,000	
73	BNPP	9538	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	40,000	
74	MACQUARIE	9573	Swap	Fixed		Nymex LD HH		Nymex	Mar-16	40,000	
75	**TOTAL**										**$ 6,681,995**

	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	Volume	Dollar Amount
1	MITSUI	10045	Swap	Nymex LD HH		GD HH		Nymex	Apr-16	160,000	
2	BNPP	10044	Swap	Nymex LD HH		GD HH		Nymex	Apr-16	900,000	
3	JPMORG	10043	Swap	Nymex LD HH		GD HH		Nymex	Apr-16	1,200,000	
4	BARCLAY	7483	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	20,000	
5	BARCLAY	7619	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	10,000	
6	BARCLAY	7692	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	10,000	
7	BARCLAY	7713	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	10,000	
8	BARCLAY	7937	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	30,000	
9	BARCLAY	7998	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	20,000	
10	BARCLAY	8010	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	20,000	
11	BARCLAY	8072	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	20,000	
12	CIBC	9098	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	55,000	
13	CIBC	9949	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	20,000	
14	JPMORG	7552	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	20,000	
15	JPMORG	7815	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	30,000	
16	JPMORG	7893	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	40,000	
17	JPMORG	7926	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	30,000	
18	JPMORG	8033	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	20,000	
19	JPMORG	8085	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	20,000	
20	JPMORG	8347	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	50,000	
21	JPMORG	8384	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	40,000	
22	JPMORG	8453	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	40,000	
23	JPMORG	8470	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	40,000	
24	JPMORG	8549	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	60,000	
25	JPMORG	8583	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	70,000	
26	JPMORG	8857	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	30,000	
27	JPMORG	9040	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	125,000	
28	JPMORG	9955	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	150,000	
29	JPMORG	9956	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	40,000	
30	MITSUI	9928	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	30,000	
31	MITSUI	9965	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	50,000	
32	CITIGR	8495	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	50,000	
33	CARGILL	8396	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	40,000	
34	CARGILL	9242	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	40,000	
35	MERRIL	7879	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	40,000	
36	MERRIL	8213	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	30,000	
37	MERRIL	8339	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	50,000	
38	MERRIL	8358	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	30,000	
39	MERRIL	8410	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	40,000	
40	MERRIL	8433	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	30,000	
41	MERRIL	8601	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	50,000	
42	MERRIL	8742	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	40,000	
43	MERRIL	8766	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	30,000	
44	MERRIL	9097	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	70,000	
45	CITIGR	7571	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	10,000	
46	CITIGR	8250	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	40,000	
47	CITIGR	8320	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	50,000	
48	CITIGR	8523	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	50,000	
49	CITIGR	8714	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	40,000	
50	CITIGR	8753	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	40,000	
51	CITIGR	9216	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	60,000	
52	SHELLTRADE	7827	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	30,000	
53	SHELLTRADE	8115	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	30,000	
54	BNPP ET	7598	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	10,000	
55	BNPP ET	7673	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	10,000	
56	BNPP ET	7684	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	20,000	
57	BNPP ET	7711	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	30,000	
58	BNPP ET	8043	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	20,000	
59	BNPP ET	8146	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	40,000	
60	BNPP	8306	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	50,000	
61	BNPP	8573	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	50,000	
62	BNPP	8646	Swap	Fixed		Nymex LD HH		Nymex	Apr-16	40000	
63	**TOTAL**										**$ 5,239,140**

	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	Volume	Dollar Amount
1	JPMORG	10078	Swap	Fixed		Nymex LD HH		Nymex	May-16	930,000	
2	MITSUI	10081	Swap	Fixed		Nymex LD HH		Nymex	May-16	1,240,000	
3	SHELLTRADE	10082	Swap	Fixed		Nymex LD HH		Nymex	May-16	320,000	
4	BARCLAY	7483	Swap	Fixed		Nymex LD HH		Nymex	May-18	20,000	
5	BARCLAY	7619	Swap	Fixed		Nymex LD HH		Nymex	May-18	10,000	
6	BARCLAY	7692	Swap	Fixed		Nymex LD HH		Nymex	May-16	10,000	
7	BARCLAY	7713	Swap	Fixed		Nymex LD HH		Nymex	May-16	10,000	
8	BARCLAY	7937	Swap	Fixed		Nymex LD HH		Nymex	May-16	30,000	
9	BARCLAY	7998	Swap	Fixed		Nymex LD HH		Nymex	May-16	20,000	
10	BARCLAY	8010	Swap	Fixed		Nymex LD HH		Nymex	May-16	20,000	
11	BARCLAY	8072	Swap	Fixed		Nymex LD HH		Nymex	May-16	20,000	
12	CIBC	9098	Swap	Fixed		Nymex LD HH		Nymex	May-16	55,000	
13	CIBC	9949	Swap	Fixed		Nymex LD HH		Nymex	May-16	20,000	
14	JPMORG	7552	Swap	Fixed		Nymex LD HH		Nymex	May-16	20,000	
15	JPMORG	7815	Swap	Fixed		Nymex LD HH		Nymex	May-16	30,000	
16	JPMORG	7893	Swap	Fixed		Nymex LD HH		Nymex	May-16	40,000	
17	JPMORG	7926	Swap	Fixed		Nymex LD HH		Nymex	May-18	30,000	
18	JPMORG	8033	Swap	Fixed		Nymex LD HH		Nymex	May-16	20,000	
19	JPMORG	8085	Swap	Fixed		Nymex LD HH		Nymex	May-16	20,000	
20	JPMORG	8347	Swap	Fixed		Nymex LD HH		Nymex	May-18	50,000	
21	JPMORG	8384	Swap	Fixed		Nymex LD HH		Nymex	May-16	40,000	
22	JPMORG	8470	Swap	Fixed		Nymex LD HH		Nymex	May-16	40,000	
23	JPMORG	8549	Swap	Fixed		Nymex LD HH		Nymex	May-16	60,000	
24	JPMORG	8583	Swap	Fixed		Nymex LD HH		Nymex	May-16	70,000	
25	JPMORG	8857	Swap	Fixed		Nymex LD HH		Nymex	May-16	30,000	
26	JPMORG	9040	Swap	Fixed		Nymex LD HH		Nymex	May-16	125,000	
27	JPMORG	9955	Swap	Fixed		Nymex LD HH		Nymex	May-16	150,000	
28	JPMORG	9956	Swap	Fixed		Nymex LD HH		Nymex	May-16	40,000	
29	MITSUI	9928	Swap	Fixed		Nymex LD HH		Nymex	May-18	30,000	
30	MITSUI	9965	Swap	Fixed		Nymex LD HH		Nymex	May-16	50,000	
31	CITIGR	8495	Swap	Fixed		Nymex LD HH		Nymex	May-16	50,000	
32	CARGILL	8396	Swap	Fixed		Nymex LD HH		Nymex	May-16	40,000	
33	CARGILL	8949	Swap	Fixed		Nymex LD HH		Nymex	May-16	40,000	
34	CARGILL	9242	Swap	Fixed		Nymex LD HH		Nymex	May-16	40,000	
35	MERRIL	7879	Swap	Fixed		Nymex LD HH		Nymex	May-16	40,000	
36	MERRIL	8213	Swap	Fixed		Nymex LD HH		Nymex	May-16	30,000	
37	MERRIL	8339	Swap	Fixed		Nymex LD HH		Nymex	May-16	50,000	
38	MERRIL	8358	Swap	Fixed		Nymex LD HH		Nymex	May-16	30,000	
39	MERRIL	8410	Swap	Fixed		Nymex LD HH		Nymex	May-16	40,000	
40	MERRIL	8433	Swap	Fixed		Nymex LD HH		Nymex	May-16	30,000	
41	MERRIL	8601	Swap	Fixed		Nymex LD HH		Nymex	May-16	50,000	
42	MERRIL	8742	Swap	Fixed		Nymex LD HH		Nymex	May-16	40,000	
43	MERRIL	8766	Swap	Fixed		Nymex LD HH		Nymex	May-18	30,000	
44	MERRIL	9097	Swap	Fixed		Nymex LD HH		Nymex	May-16	70,000	
45	MERRIL	9236	Swap	Fixed		Nymex LD HH		Nymex	May-16	40,000	
46	MERRIL	9958	Swap	Fixed		Nymex LD HH		Nymex	May-16	110,000	
47	CITIGR	7571	Swap	Fixed		Nymex LD HH		Nymex	May-16	10,000	
48	CITIGR	8250	Swap	Fixed		Nymex LD HH		Nymex	May-16	40,000	
49	CITIGR	8320	Swap	Fixed		Nymex LD HH		Nymex	May-16	50,000	
50	CITIGR	8523	Swap	Fixed		Nymex LD HH		Nymex	May-16	50,000	
51	CITIGR	8714	Swap	Fixed		Nymex LD HH		Nymex	May-16	40,000	
52	CITIGR	8753	Swap	Fixed		Nymex LD HH		Nymex	May-16	40,000	
53	CITIGR	8783	Swap	Fixed		Nymex LD HH		Nymex	May-18	20,000	
54	CITIGR	9216	Swap	Fixed		Nymex LD HH		Nymex	May-16	60,000	
55	SHELLTRADE	7827	Swap	Fixed		Nymex LD HH		Nymex	May-16	30,000	
56	SHELLTRADE	8115	Swap	Fixed		Nymex LD HH		Nymex	May-16	30,000	
57	SHELLTRADE	8984	Swap	Fixed		Nymex LD HH		Nymex	May-16	40,000	
58	BNPP ET	7598	Swap	Fixed		Nymex LD HH		Nymex	May-16	10,000	
59	BNPP ET	7673	Swap	Fixed		Nymex LD HH		Nymex	May-16	10,000	
60	BNPP ET	7684	Swap	Fixed		Nymex LD HH		Nymex	May-18	20,000	
61	BNPP ET	7711	Swap	Fixed		Nymex LD HH		Nymex	May-16	30,000	
62	BNPP ET	8043	Swap	Fixed		Nymex LD HH		Nymex	May-16	20,000	
63	BNPP ET	8146	Swap	Fixed		Nymex LD HH		Nymex	May-16	40,000	
64	BNPP	8306	Swap	Fixed		Nymex LD HH		Nymex	May-16	50,000	
65	BNPP	8573	Swap	Fixed		Nymex LD HH		Nymex	May-16	50,000	
66	BNPP	8646	Swap	Fixed		Nymex LD HH		Nymex	May-16	40,000	
67	BNPP	8818	Swap	Fixed		Nymex LD HH		Nymex	May-16	20000	
68	**TOTAL**										**$ 5,718,593**

	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	Volume	Dollar Amount
1	JPMORG	10100	Swap	Nymex LD HH		GD HH		Nymex	Jun-16	1,500,000	
2	MITSUI	10102	Swap	Nymex LD HH		GD HH		Nymex	Jun-16	160,000	
3	BNPP	10101	Swap	Nymex LD HH		GD HH		Nymex	Jun-16	1,500,000	
4	BARCLAY	7483	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	20,000	
5	BARCLAY	7619	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	10,000	
6	BARCLAY	7692	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	10,000	
7	BARCLAY	7713	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	20,000	
8	BARCLAY	7937	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	30,000	
9	BARCLAY	7998	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	20,000	
10	BARCLAY	8010	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	20,000	
11	BARCLAY	8072	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	20,000	
12	BARCLAY	9844	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	60,000	
13	CIBC	9098	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	55,000	
14	CIBC	9428	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
15	CIBC	9949	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	20,000	
16	JPMORG	7552	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	20,000	
17	JPMORG	7815	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	30,000	
18	JPMORG	7893	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
19	JPMORG	7926	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	30,000	
20	JPMORG	8033	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	20,000	
21	JPMORG	8085	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	30,000	
22	JPMORG	8347	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	50,000	
23	JPMORG	8384	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
24	JPMORG	8453	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
25	JPMORG	8470	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
26	JPMORG	8549	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	60,000	
27	JPMORG	8583	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	70,000	
28	JPMORG	8857	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	30,000	
29	JPMORG	9040	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	125,000	
30	JPMORG	9287	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	30,000	
31	JPMORG	9853	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	60,000	
32	JPMORG	9955	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	150,000	
33	JPMORG	9956	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
34	MITSUI	9833	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	60,000	
35	MITSUI	9903	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	60,000	
36	MITSUI	9923	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	60,000	
37	MITSUI	9928	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	30,000	
38	MITSUI	9965	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	50,000	
39	CITIGR	8495	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	50,000	
40	CARGILL	8396	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
41	CARGILL	8949	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
42	CARGILL	9242	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
43	MERRIL	7879	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
44	MERRIL	8213	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	30,000	
45	MERRIL	8339	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	50,000	
46	MERRIL	8358	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	30,000	
47	MERRIL	8410	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
48	MERRIL	8433	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	30,000	
49	MERRIL	8601	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	50,000	
50	MERRIL	8742	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
51	MERRIL	8766	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	30,000	
52	MERRIL	9097	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	70,000	
53	MERRIL	9236	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
54	MERRIL	9321	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
55	MERRIL	9958	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	110,000	
56	CITIGR	7571	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	10,000	
57	CITIGR	8250	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
58	CITIGR	8320	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	50,000	
59	CITIGR	8523	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	50,000	
60	CITIGR	8714	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
61	CITIGR	8753	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
62	CITIGR	8783	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	20,000	
63	CITIGR	9216	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	60,000	
64	CITIGR	9256	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
65	SHELLTRADE	7827	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	30,000	
66	SHELLTRADE	8115	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	30,000	
67	SHELLTRADE	8984	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
68	BNPP ET	7598	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	10,000	
69	BNPP ET	7673	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	10,000	
70	BNPP ET	7684	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	20,000	
71	BNPP ET	7711	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	30,000	
72	BNPP ET	8043	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	20,000	
73	BNPP ET	8146	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
74	BMO	7856	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
75	BMO	9487	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	

	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	Volume	Dollar Amount
76	BNPP	8306	Swap	Fixed	[redacted]	Nymex LD HH	[redacted]	Nymex	Jun-16	50,000	[redacted]
77	BNPP	8573	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	50,000	
78	BNPP	8646	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
79	BNPP	8818	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	20,000	
80	BNPP	9538	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
81	MACQUARIE	9573	Swap	Fixed		Nymex LD HH		Nymex	Jun-16	40,000	
82	**TOTAL**										**$ 4,737,258**

	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	Volume	Dollar Amount
1	BARCLAY	10134	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	620,000	
2	MITSUI	10132	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	1,240,000	
3	MORGAN	10135	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	80,000	
4	JPMORG	10133	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	620,000	
5	BARCLAY	7483	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	20,000	
6	BARCLAY	7619	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	10,000	
7	BARCLAY	7692	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	10,000	
8	BARCLAY	7713	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	20,000	
9	BARCLAY	7937	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	30,000	
10	BARCLAY	7998	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	20,000	
11	BARCLAY	8010	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	20,000	
12	BARCLAY	8072	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	20,000	
13	BARCLAY	9844	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	60,000	
14	CIBC	9098	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	55,000	
15	CIBC	9428	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
16	CIBC	9949	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	20,000	
17	JPMORG	7552	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	20,000	
18	JPMORG	7815	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	30,000	
19	JPMORG	7893	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
20	JPMORG	7926	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	30,000	
21	JPMORG	8033	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	20,000	
22	JPMORG	8085	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	30,000	
23	JPMORG	8347	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	50,000	
24	JPMORG	8384	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
25	JPMORG	8453	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
26	JPMORG	8470	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
27	JPMORG	8549	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	60,000	
28	JPMORG	8583	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	70,000	
29	JPMORG	8857	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	30,000	
30	JPMORG	9040	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	125,000	
31	JPMORG	9287	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	30,000	
32	JPMORG	9853	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	60,000	
33	JPMORG	9955	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	150,000	
34	JPMORG	9956	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
35	MITSUI	9833	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	60,000	
36	MITSUI	9903	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	60,000	
37	MITSUI	9923	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	60,000	
38	MITSUI	9928	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	30,000	
39	MITSUI	9965	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	50,000	
40	CITIGR	8495	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	50,000	
41	CARGILL	8396	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
42	CARGILL	8949	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
43	CARGILL	9242	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
44	MERRIL	7879	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
45	MERRIL	8213	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	30,000	
46	MERRIL	8339	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	50,000	
47	MERRIL	8358	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	30,000	
48	MERRIL	8410	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
49	MERRIL	8433	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	30,000	
50	MERRIL	8601	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	50,000	
51	MERRIL	8742	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
52	MERRIL	8766	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	30,000	
53	MERRIL	9097	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	70,000	
54	MERRIL	9236	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
55	MERRIL	9321	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
56	MERRIL	9958	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	110,000	
57	CITIGR	7571	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	10,000	
58	CITIGR	8250	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
59	CITIGR	8320	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	50,000	
60	CITIGR	8523	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	50,000	
61	CITIGR	8714	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
62	CITIGR	8753	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
63	CITIGR	8783	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	20,000	
64	CITIGR	9216	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	60,000	
65	CITIGR	9256	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
66	SHELLTRADE	7827	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	30,000	
67	SHELLTRADE	8115	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	30,000	
68	SHELLTRADE	8984	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
69	BNPP ET	7598	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	10,000	
70	BNPP ET	7673	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	10,000	
71	BNPP ET	7684	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	20,000	
72	BNPP ET	7711	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	30,000	
73	BNPP ET	8043	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	20,000	
74	BNPP ET	8146	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
75	BMO	7856	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	

	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	Volume	Dollar Amount
76	BMO	9487	Swap	Fixed	[redacted]	Nymex LD HH	[redacted]	Nymex	Jul-16	40,000	[redacted]
77	BNPP	8306	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	50,000	
78	BNPP	8573	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	50,000	
79	BNPP	8646	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
80	BNPP	8818	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	20,000	
81	BNPP	9538	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
82	MACQUARIE	9573	Swap	Fixed		Nymex LD HH		Nymex	Jul-16	40,000	
83	**TOTAL**										**$ 3,826,500**

GULF POWER COMPANY

Risk Management Plan
For
Fuel Procurement
Docket No. 160001-EI

Date of Filing: August 4, 2016

GULF POWER

A SOUTHERN COMPANY

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 43
PARTY: GULF POWER COMPANY – (DIRECT)
DESCRIPTION: H. R. Ball HRB-5

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GULF POWER
COAL PROCUREMENT STRATEGY FOR 2017

Coal Procurement Plan

Based on the burn forecast from the July update to the Energy Budget, Gulf Power's 50% ownership in Plant Daniel has an estimated uncommitted coal supply need of [redacted] tons in 2017 and Gulf Power's 25% ownership in Plant Scherer Unit 3 has an estimated uncommitted coal supply need of [redacted] tons in 2017. Because Gulf Power's Plant Crist has a requirements contract in place for 2017 there is no uncommitted coal supply in that year. Coal burn continues to remain depressed as a result of low natural gas pricing and decreased loads. Our procurement plan below is based on the following assumptions:

Plant Crist

- Short Term: Its current marginal fuel selection consists of a requirement contract of low-sulfur Illinois Basin (IB) sourced coal.
- Long term: Current plan is to continue to utilize the most economic source of coal, which is anticipated to be either a blend of IB and other bituminous low-sulfur sourced coal or low-sulfur IB coal.
- Plant Crist is forecasted to have a capacity factor of [redacted] through 2020. An evaluation of the timing of when Crist units will be generating electricity provides insight into how coal deliveries should be procured. We forecast Crist to have at least one unit on line a majority of the time.

Plant Daniel

- Short Term: Its current marginal fuel selection consists of an 80% Powder River Basin (PRB) and 20% bituminous low sulfur blend (either Colombian or Colorado depending on market price).
- Long term: Current plan is to continue to utilize the 80/20 blend of PRB and other bituminous low-sulfur sourced coal
- Plant Daniel is forecasted to have a capacity factor of [redacted] through 2020. An evaluation of the timing of when Daniel units will be generating electricity provides insight into how coal deliveries should be procured. We forecast Daniel to have at least one unit on line a majority of the time

Plant Scherer Unit 3

- Short Term: Its current marginal fuel selection is 100% PRB.
- Long term: Current plan is to continue to utilize 100% PRB
- Plant Scherer Unit 3 is forecasted to have a capacity factor of [redacted] through 2020. An evaluation of the timing of when Scherer units will be generating electricity provides insight into how coal deliveries should be procured.

State of the Program:

The relationship between burn projections, current commitment levels, commitment targets per the coal procurement strategy, and corresponding future needs are detailed in the following charts:

Gulf Program Plant Crist



MPC Program Plant Daniel-Gulf Ownership (50%)



GPC Program Plant Scherer-Gulf Ownership (25% of Unit 3)

[redacted]

Spot Coal Plan:

Quarterly system-wide bituminous and sub-bituminous solicitations will be issued as needed to address short term coal supply needs that may develop. With the uncertainty of burn that still exists today and with many coal units being displaced by natural gas generation, this quarterly process provides flexibility to better manage burn volatility. Gulf will purchase spot coal under these quarterly solicitations as the need arises.

Long-term Coal Plan:

Due to a requirements coal contract in place for 2017 Gulf's Plant Crist is fully committed that year. [redacted]

Gulf's 50% ownership in MPC Plant Daniel has [redacted] Gulf's 25% ownership in Plant Scherer Unit 3 results in [redacted]

[redacted] System-wide long-term bituminous and sub bituminous solicitations will be issued late 2016 and/or early 2017 and Gulf will evaluate the need for long-term purchases for delivery beginning in 2017. The purchases made will adhere to the percentage commitment guidelines set forth in the Coal Procurement Strategy.

GULF POWER
COAL TRANSPORTATION STRATEGY FOR 2017

Transportation Program Overview

Plant Crist

Crist can receive both import and domestic coal by barge.

Western coals can be transported by the Burlington Northern Santa Fe Railway (BNSF) or Union Pacific Railroad (UP) to multiple terminals on the Ohio and Mississippi rivers or via interchanges with the Canadian National Railway (CN), Norfolk Southern (NS) or CSX Transportation Inc. (CSXT) to the Alabama State Docks facility in Mobile, AL.

Illinois Basin or Central Appalachian coal can be transported directly by barge or by a combination of rail and barge. These coals can be transported to the Alabama State Docks facility via interchanges with the Canadian National Railway (CN), CSX Transportation Inc. (CSXT), Alabama and Gulf Coast Railway (AGR), and Norfolk Southern (NS) railroads. At this point the coal is transferred to barges and transported to the plants.

Import coal is delivered by ocean vessel to the Alabama State Docks where it is transferred to barges and transported to the plants.

Plant Daniel

Daniel is served by the Mississippi Export Railroad (MSE) that interchanges with the CSXT and the CN. Daniel accesses Powder River Basin (PRB) and Colorado coal sources via multiple rail interchanges with the MSE from the BNSF, UP and CN railroads.

Daniel can also take advantage of import coals, when economical, through the Alabama State Docks. Import coal is transported by ocean vessel to the Alabama State Docks facility where it is transferred to railcars for shipment to the plant by the CN and MSE Railroads. Daniel can also receive Central Appalachian coal via the CSXT and MSE. Another potential source of Central Appalachian coal is via the NS railroad through an interchange agreement with the CN railroad.

Plant Scherer

Scherer is served by the Norfolk Southern Railroad (NS) that interchanges with the BNSF Railway (BNSF). Scherer accesses Powder River Basin (PRB) coal, its long term coal of choice, from Wyoming through an NS interchange with the BNSF at Memphis, TN. Should Scherer decide to change its current coal selection, it could receive coal directly from NS served Illinois Basin, Central or Northern Appalachian coal fields, import coal terminals or through various NS interchanges with UP, CN or CSX.

Coal Transportation Procurement Strategy

A transportation strategy must address reliability, competitive prices, flexibility in volume commitments and the ability to adjust coal movements to changing coal supply sources. The following information addresses these areas and identifies tactical plans to manage them.

Plant Crist

Effective August 2016, CSX contract 15164 provides rail transportation of Illinois Basin Coal to the Alabama State Docks. This contract will expire December 31,

2017. Gulf will pursue an extension if transportation needed beyond the current term.

Marquette agreement (SC09005-T) provides primary barge transportation of coal from the Alabama State Docks to Crist. Marquette agreement (SC09006-T) provides a supply of barges to move coal to Crist. The Marquette agreements have been extended through December 31, 2017.

Under these agreements, Gulf charters approximately 18 barges from Marquette. The agreement with Marquette also includes towboat services to support transport of coal to the plants. Two towboats are used to transport coal by barge to Crist. There are no minimum annual volumes included in the agreements.

The tactical plan for the Marquette agreements is to maintain the agreements through 2017 at reduced levels in order to match reduced levels of coal shipments in 2016 and 2017. The Marquette agreements provide a very stable and flexible supply of towboats and barges that have logistical control by Southern Company Generation Fuel Services for Gulf.

Plant Daniel

UP agreement UPCQ 100910 provides for rail transportation of Colorado coal to Memphis in conjunction with the CN agreement for final delivery to Daniel through December 31, 2016. The tactical plan is to let this agreement expire unless additional Western coal is required for blending in 2017.

BNSF agreement BNSF-12777 provides for rail transportation of PRB coal to Memphis, TN where BNSF interchanges with CN to deliver the PRB coal to Daniel. The BNSF agreement expires December 31, 2017. The tactical plan is to submit the movement for competitive bid during the third quarter of 2017 to cover shipments in 2018.

CN/MSE agreement CN-535188-AA provides for rail transportation of PRB and Colorado coal interchanged in Memphis, TN to Daniel. Additionally, this agreement provides transportation for Illinois Basin coal from CN served origins and the for import coal from the Alabama State Docks. The CN/MSE agreement expires December 31, 2018.

Plant Scherer

BNSF agreement BNSF-12339 provides for rail transportation of PRB coal to Memphis, TN where BNSF interchanges with NS to deliver the PRB coal to Scherer. The BNSF agreement expires December 31, 2028. The tactical plan is to maintain this contract through its expiration.

NS agreement NS-9793 provides for rail transportation of PRB coal from its interchange with the BNSF at Memphis to the plant. The NS agreement expires December 31, 2019. The tactical plan is to maintain this contract through its expiration and begin the negotiation of an extension of the contract in the first quarter of 2019.

Gulf Power 2017 Natural Gas Procurement Strategy

Gas Program Overview

Natural Gas is used for primary fuel at the Smith 3 combined cycle unit, boiler lighter fuel at Crist Units 4-7, and for generation secured under purchased power agreements beginning in 2009. Prior to 2002, natural gas represented a relatively small portion of Gulf's overall fuel budget. With the addition of the combined-cycle Smith 3 unit in 2002 and the Central Alabama PPA in 2009, natural gas became a more significant portion of Gulf's overall fuel supply.

Gulf Power's natural gas procurement strategy is to purchase a cost effective yet highly reliable fuel supply to support the operation of its generating facilities. Securing competitive fuel prices for its customers and minimizing both price and supply risk are the governing considerations in developing Gulf's fuel procurement strategy.

Projected Natural Gas Purchases

Southern Company Services (SCS) as agent for Gulf purchases natural gas to be delivered to Plant Crist for lighter purposes on the coal fired units and to Plant Smith as primary fuel for Unit 3 which is a combined cycle generating unit. SCS will also purchase natural gas to serve as primary fuel for the Shell (Central Alabama) purchased power agreement. Gulf has contracted for storage capacity at Bay Gas Storage near Mobile, AL, Leaf River Energy Center near Richton, MS, and at Southern Pines Energy Center near Hattiesburg, MS and will purchase natural gas to maintain targeted quantities of gas in storage during the year. Gas storage provides operational flexibility by providing an alternative destination for daily gas

purchases when gas burn variations occur and gas supply reliability when normal gas supply interruptions occur.

Procurement Strategy

Gulf's strategy for gas procurement is to purchase the commodity using long term and spot agreements at market prices. Fuel purchased at market over a long period is a low cost option for customers.

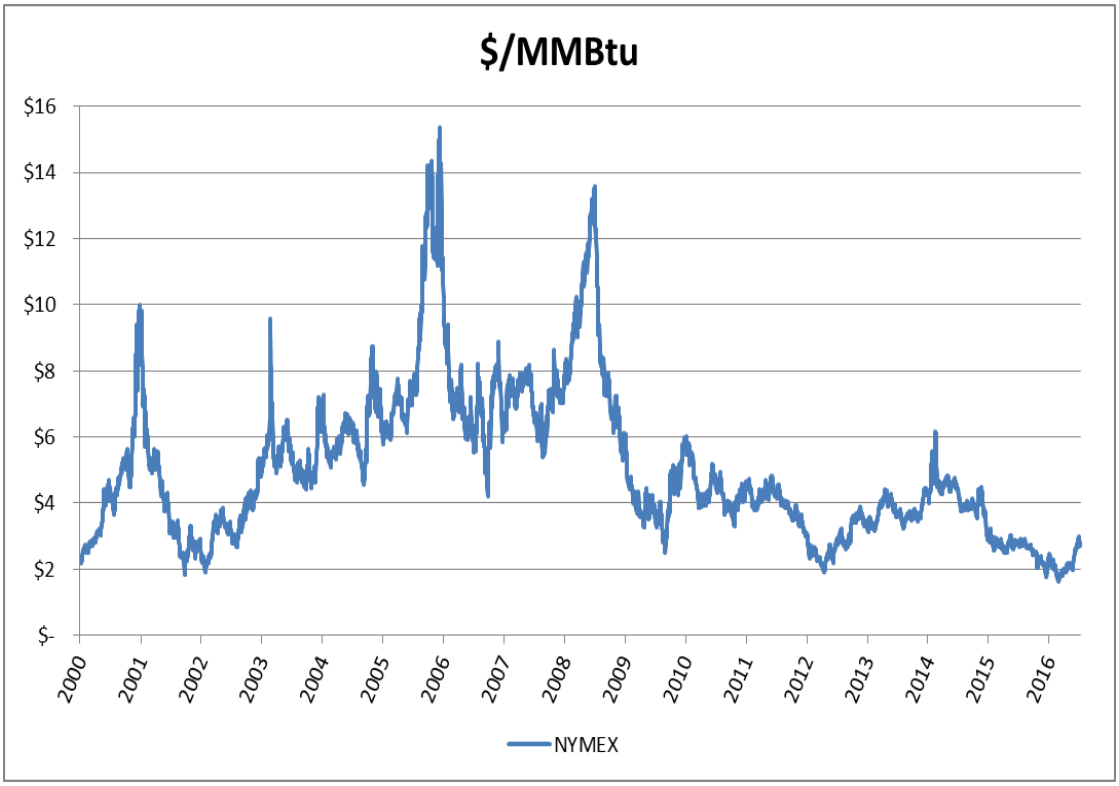
[redacted]

For Gulf, spot-market contracts have a term of less than one year and long-term contracts have a term of 1 year or longer. All natural gas, regardless of whether it is bought under long-term contracts or spot-market contracts, is purchased at market based prices. While fuel purchased at market over long periods is a low cost option for customers, it does expose the customers to short-term price volatility. Since these price fluctuations can be severe, Gulf Power, at the direction of the Florida Public Service Commission, will attempt to protect its customers against short-term price volatility by utilizing hedging tools. It is understood that the cost of hedging will sometimes lead to fuel costs that are higher than market prices but that this is a reasonable trade-off for reducing the customers' exposure to fuel cost increases that

would result if fuel prices actually settle at higher prices than when the hedges were placed.

The following graph of actual natural gas prices is an indication of price volatility in the gas commodity market:

Historical Natural Gas Prices – NYMEX



Pricing Strategy

Gulf Power will continue to purchase gas, both under long-term and spot contracts at market based prices. However, pursuant to Commission order, Gulf Power will financially hedge gas prices for some portion, generally between [redacted] percent of Gulf Power's projected annual gas burn for the current year, in order to protect against short-term price swings and to provide some level of price certainty. This [redacted]

[redacted]percent hedge range allows Gulf Power to provide a degree of price certainty and protection against short-term price swings while still allowing the customers to participate in markets where natural gas prices are low. Gulf Power will secure natural gas hedges over a time period not to exceed [redacted] months, per the following schedule:

	(A)	(B)
Period	**Lower Target Hedge %**	**Upper Target Hedge %**
Prompt Year (2017)	[redacted]	[redacted]
Year 2 (2018)	[redacted]	[redacted]
Year 3 (2019)	[redacted]	[redacted]
Year 4 (2020)	[redacted]	[redacted]

Note: The annual hedge percentage is based on the budgeted annual gas burn

Although SCS will target the levels shown in the table above, SCS may accelerate or decelerate the plan accordingly based on market conditions. Gulf's hedging targets are expressed on an annual basis due to the potential for large variances in month to month gas consumption. The monthly variance in gas burn is due to Gulf's units being dispatched on an economic basis with the other generating units in the Southern electric system and the impact of unit outages on Gulf's total gas burn.

SCS, working in partnership with Gulf Power, develops short-term hedge strategies based on current and projected market conditions. [redacted] SCS will employ both technical and fundamental analysis to determine appropriate times to hedge. However, the

objective is not to speculate on market price or attempt to outguess or “beat the market”. Gulf will utilize fixed priced swaps as its primary financial gas price hedging instrument but may also utilize options when appropriate.

While the hedging program will protect the customer from short-term price spikes, hedges can also lead to higher costs when natural gas prices fall subsequent to entering hedges. Gulf Power will limit the amount of fixed-price hedges to a maximum of [redacted] percent of the projected fuel burn for the upcoming year. In addition, Gulf Power will limit option priced hedges to [redacted] percent of its projected burn. Finally, in order to protect its customers from market exposure in subsequent years, Gulf Power will take forward hedge positions for up to [redacted] months into the future.

Gulf Power's 2017 Oil Procurement Strategy

Oil Program Overview

Oil is used at Gulf predominantly for boiler lighting. Oil is used as a boiler lighter fuel at Crist units 4-7, Daniel 1&2, and Scherer 3. Oil is also the primary fuel at the Smith A CT unit and is back-up fuel at the Shell (Central Alabama) CC Plant currently under a purchase power agreement with Gulf. Overall, oil use is projected to be a small portion of Gulf's overall fuel budget.

Procurement Strategy

Gulf's strategy for oil procurement is to purchase the commodity at market prices. Fuel purchased at-market over a long period is a low cost option for customers.

Gulf purchases fuel oil on an annual basis through a formal bidding process. As part of this bidding process, Gulf negotiates predetermined contracts to set the index based market price for the commodity and delivery adders for fuel oil delivery to each plant. As inventories are depleted during the year, Gulf will purchase additional fuel oil quantities based on the negotiated contract for the plant.

Pricing Strategy

Oil pricing will be indexed to current market prices at the time purchases are made. Since fuel oil is such a small portion of the overall fuel budget, Gulf does not plan to financially hedge oil prices.

Gulf Power Company Risk Management Policy

I. Introduction

Natural gas has become a large part of the Gulf Power Company (Company) fuel program. This increased need, combined with the market price volatility associated with natural gas and purchased energy, has created a need to begin hedging the risks related to the Company's overall fuel program.

II. Objectives

The primary objective of this Risk Management Policy (RMP) is to establish guidelines for use of hedging transactions associated with the Company's fuel program. Hedging transactions will allow the Company to:

- Reduce price volatility
- Provide more predictable stability to customers, and
- Provide additional flexibility and options in the procurement of fuel.

III. Guidelines

The risk management guidelines of The Southern Company require any business unit engaging in risk management activities to establish a Risk Oversight Committee (ROC). The officer listed below in Section IV will serve as the Company's ROC for this program.

The Southern Company Derivatives Policy states:

> "It is the policy of The Southern Company that derivatives are to be used only in a controlled manner, which includes identification, measurement, management, control and monitoring of risks. This includes, but is not limited to, well-defined segregation of duties, limits on capital at risk, and established credit policies. When the use of

derivatives is contemplated, this policy requires that a formal risk management plan be developed that adheres to The Southern Company Risk Oversight Committee Business Unit Guidelines. This policy also requires that, prior to initiation of a risk management program that makes use of derivatives, the risk management program must be approved by both the Chief Financial Officer of the respective Southern Company subsidiary and the Chief Financial Officer of The Southern Company."

The Southern Company Generation Risk Management Policy (SCGen RMP), attached in Section 6 of this document, will be the governing policy in the administration of the Company's fuel procurement program. The SCGen RMP provides all criteria specified in the above extract from the Southern Company Derivatives Policy.

The Gulf Power Company Board of Directors has authorized the use of hedging transactions relating to contracts and other agreements for fuel supplies. The board resolution is shown below:

"**RESOLVED,** That The Southern Company System Policy on Use of Derivatives (the "Policy") as presented to the meeting is hereby approved; and

RESOLVED FURTHER, That the Officers are hereby authorized to effect derivative transactions that comply with the policy, including swaps, caps, collars, floors, swap options, futures, forward and options, relating to energy and associated

commodities, weather, interest rates, currencies, and contracts and other arrangements for fuel supplies; and

RESOLVED FURTHER, That in connection with the foregoing, the officers are hereby authorized to take any and all actions and to execute, deliver and perform on behalf of the Company any and all agreements and other instruments as they consider necessary, appropriate or advisable, each such agreement or other instrument to be in such form as the officers executing the same shall approve, the execution thereof to constitute conclusive evidence of such approval."

IV. Process

Certain officers of the Company were given authority to enter into hedging transactions that they consider necessary in order to reduce risk associated with procuring fuel and energy. The authorized officers are Vice President, Chief Financial Officer and Comptroller for Gulf Power Company or his designee.

Once authorization has been received, Southern Company Services Fuel Services, agent for Gulf Power Company, will conduct all hedging transactions in accordance with the Southern Company Generation Risk Management Policy.

It is the responsibility of SCGen Risk Control (the mid-office) to inform the Fuel Manager for Gulf Power Company or the Regulatory Accounting Manager for Gulf Power Company about the use of hedging transactions associated with Gulf generation resources and to provide open position values (mark to market) to the above noted individuals and the Gulf Chief Financial Officer and Comptroller.

Southern Company
Energy Trading Risk Management Policy

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I. Purpose

This Southern Company Energy Trading Risk Management Policy ("RMP") applies to energy related trading, hedging, and procurement activities, performed by Authorized Individuals, as defined in Appendix D of this RMP, and the associated risk management activities as defined within this RMP. The purpose of this RMP is to:

- Provide collective limits and preset guidelines for each employee authorized to legally bind Southern Company Services and the related Operating Companies (collectively, the "Company") to transactions covered by this RMP;
- Establish sound guidelines to follow in managing and controlling risks; and
- Define the responsibilities for managing, monitoring, and reporting risks.

Notwithstanding anything to the contrary contained in this RMP, compliance with all legal and regulatory requirements, pronouncements, orders, etc. is required.

II. Background

In August 1997, the Southern Company Risk Oversight Committee ("SROC") approved a set of risk management guidelines. Also, at various times during 2000 through 2002, the boards of directors for Southern Company, the Operating Companies (Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company), and Southern Power Company ("SPC") adopted the Southern Company Policy on the Use of Derivatives ("Derivatives Policy"). The Derivatives Policy was updated and approved by the various boards in 2012.

During 2006, the risk oversight and governance framework for Southern Company continued to evolve to further refine the oversight structure and to reflect organizational changes since the original SROC approved risk management guidelines in August 1997. As part of this evolution, the SROC was reconstituted, and a Generation Risk Oversight Committee was formed. These groups, along with the Risk Advisory and Controls Committee, replaced the Energy Risk Management Board and assumed its responsibilities.

Effective November 19, 2007, as a result of the Separation Protocol, certain functions for SPC were separated from the Operating Companies and certain communications between them was restricted. It was decided that SPC would no longer attend or have representation on the Generation Risk Oversight Committee. This decision prompted the need separate SPC risk monitoring. The Generation Risk Oversight Committee continues to monitor the consolidated energy trading risks, including SPC positions.

The Southern Company Derivatives Policy requires any business unit engaging in energy trading and marketing activities to develop a risk management policy. This policy must be consistent with the Southern Company Enterprise Risk Management Framework document and must include, but not be limited to, well-defined segregation of duties, limits on capital at risk, credit policies, notification requirements, and proper documentation and reporting.

III. Business Objectives

The Approved Business Objectives for the trading activities performed by Authorized Individuals are defined in Appendix A.

IV. Business Strategies

The business objectives are achieved by entering into transactions involving the approved commodities shown in Appendix B.





Various contract types or financial instruments will be used to achieve the Approved Business Objectives. The Approved Risk Management Instruments are listed in Appendix C. SCS Risk Control must be consulted before the execution of any Approved Risk Management Instruments that have not been previously used, including combinations of instruments not previously used. SCS Risk Control must ensure that the requirements set forth in this RMP can be followed with respect to those instruments.

V. Authorizations

Appendix D contains the individuals, boards, and committees authorized to carry out various activities, reviews, and approvals.

VI. Segregation of Duties

The following functions are separated to ensure that the risk management activities are properly carried out:

[redacted]

[redacted]

Appendix E shows the organizational separation of function required by this RMP. The following is a summary of the responsibilities of the different functions:

Origination, Structuring, and Execution: The functions of origination, structuring, and execution include the following responsibilities:

[redacted]

[redacted]

Confirmation, Monitoring, Reporting and Disclosure: The functions of trade confirmation, risk monitoring, risk reporting, and disclosure include the following responsibilities:

[redacted]

[redacted]

Settlement: The function of settlement includes the following responsibilities:

[redacted]

Cash Management: SCS Treasury is responsible for receiving and disbursing all funds from or to counterparties and for the delivery of margin / collateral requirements. SCS Treasury will also be responsible for investment of collateral provided by counterparties.

Accounting: SCS Accounting is responsible for posting transactions to the general ledger and reconciling the subledgers to the general ledger.

VII. Market Risk Identification

[redacted]

VIII. Market Risk Measurement and Valuation

[redacted]

[redacted]

IX. Market Risk Limits

Exposure Limits

The maximum exposure limit for each business objective should not exceed the limits specified in Appendix H.

Notifications

Certain notifications to management are required as defined in Appendix G.

Volumetric Position Limits

Volumetric Position limits as defined by the Commodity Futures Trading Commission (CFTC), will be monitored and reported as necessary, according to CFTC rules.

X. Credit Risk

[redacted]

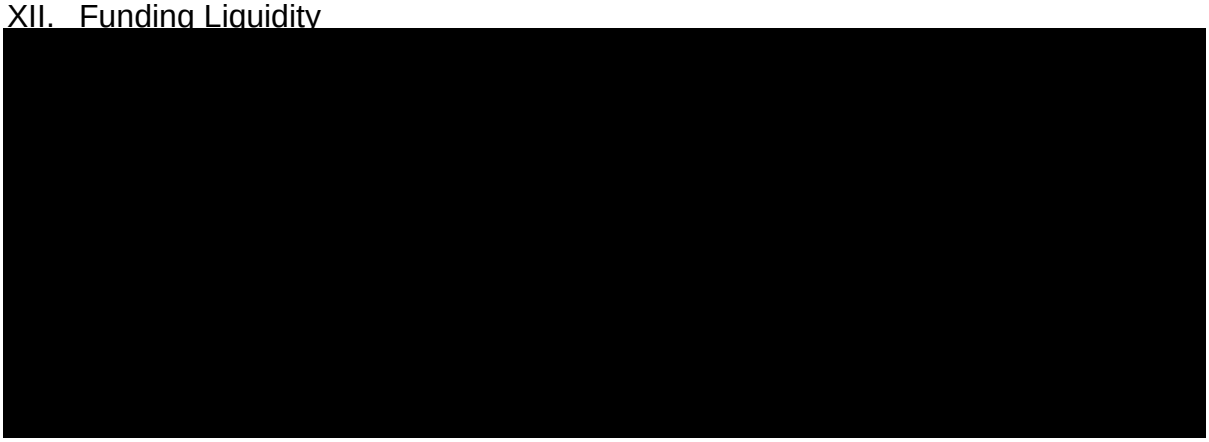
XI. New Products

Structured transactions and new products may be developed from time to time that contain new risks or require new infrastructure support. The responsibilities associated with the approval of each structured transaction and new product include the following:

[redacted]



XII. Funding Liquidity



XIII. Operating Procedures and Systems

Processes. [redacted]

Recording Transactions. [redacted]

Contract Administration. [redacted]

Operating Procedures.

XIV. Accounting,Tax, and Regulatory Reporting

XV. Legal

[redacted]

XVI. Monitoring and Reporting

SCS Risk Control personnel will calculate and report the following items on a daily basis:

[redacted]

The Portfolio Management group will prepare regular position reports. The Energy Analysis group will report preliminary gross margins or P&L on a daily basis.

XVII. Personal Trading

All employees whose activities are governed by this RMP as defined in Section XIX are prohibited from trading any approved commodity for their own account or for the benefit of any party except as specifically authorized as part of the individual's duties with the Company.

XVIII. Business Recovery

[redacted]

XIX. Compliance

[redacted]

[redacted]

XX. Independent Review

[redacted]

XXI. Policy Amendments

[redacted]

APPENDIX A

APPROVED BUSINESS OBJECTIVES

Fleet Operations and Trading

The primary objectives of Fleet Operations and Trading are to:



In addition to the primary objectives, Fleet Operations and Trading may execute secondary activities as limited by Appendix H to achieve the following secondary objectives to the extent permitted by all applicable policies and regulations:



Any Primary or Secondary Strategies that would require clearing and / or posting of margin must be approved by the Risk Advisory and Controls Committee prior to execution.

Southern Power Company Trading & Asset Management

The primary objectives of the SPC Trading and Asset Management activities are the following:



In addition to the primary objectives, SPC Trading & Asset Management may execute secondary activities as limited by Appendix H to achieve the following secondary objectives to the extent permitted by all applicable policies and regulations (including, but not limited to the IIC and Separation Protocol):



All SPC Secondary Strategies must be approved by the SPC Chief Financial Officer and the SPC Chief Commercial Officer.

Any SPC Primary or Secondary Strategies that would require clearing and / or posting of margin must be approved by the SPC Chief Financial Officer and the SPC Chief Commercial Officer.

Natural Gas Fulfillment Function

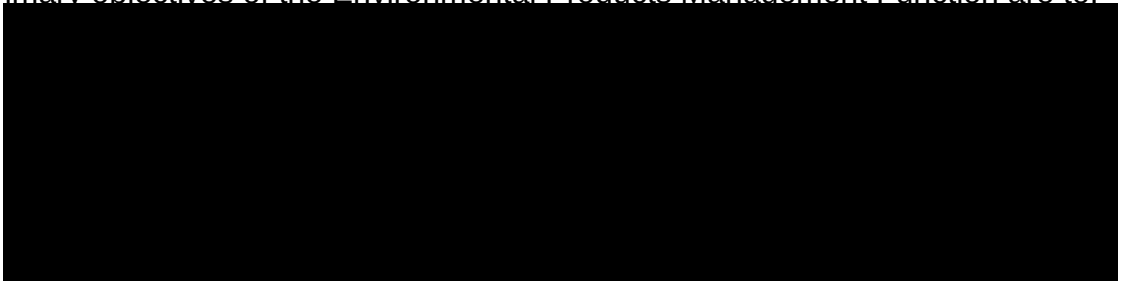
The primary objectives of the Natural Gas Fulfillment Function are to:



Secondary activities of the natural gas fulfillment function are restricted to positions intended to hedge secondary power positions, and which have been requested by Fleet Operations and Trading or SPC Trading & Asset Management.

Environmental Products Management Function

The primary objectives of the Environmental Products Management Function are to:





Secondary activities of the Environmental Products Management Function are restricted to positions intended to hedge secondary power positions, and which have been requested by Fleet Operations and Trading or SPC Trading & Asset Management.

Coal Fulfillment Function

The primary objectives of the Coal Fulfillment Function are to:



Secondary activities of the Coal Fulfillment Function are restricted to positions intended to hedge secondary power positions, and which have been requested by Fleet Operations and Trading or SPC Trading & Asset Management.

APPENDIX B

APPROVED COMMODITIES

The approved commodities for this RMP are:



APPENDIX C

APPROVED INSTRUMENTS

The approved instruments are:



APPENDIX D
AUTHORIZATIONS

Name	Authority
Southern Company Risk Oversight Committee (SROC)	[redacted]
Generation Risk Oversight Committee (GROC)	
Southern Power Risk Oversight Committee (SPROC)	
Risk Advisory and Controls Committee (RACC)	
Southern Company Generation Energy Credit Committee (ECC)	
Manager, Risk Control	

APPENDIX D
AUTHORIZATIONS (continued)
Energy Marketing

Name	Authority
Vice President, Commercial Operations & Services	[redacted]
Vice President, Chief Commercial Officer, SPC	
Sr. Vice President, Chief Financial Officer, SPC	
Vice President, Fleet Operations and Trading	

Energy Trading Manager	[redacted]
Manager, SPC Trading and Asset Management	
Term Traders	
Energy Coordinators	
Transmission Project Coordinators and Energy Schedulers	

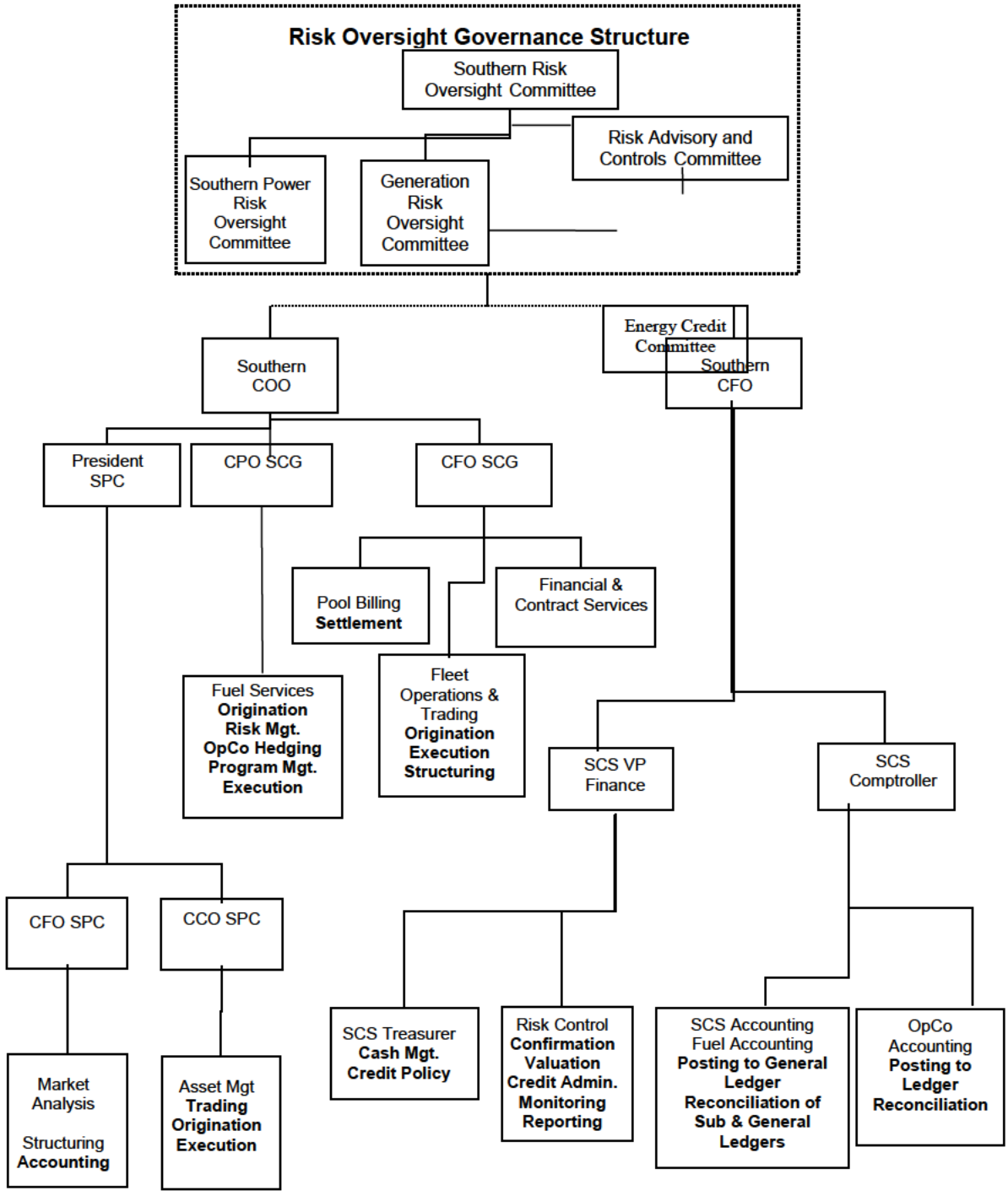
APPENDIX D
AUTHORIZATIONS (continued)
SCS Fuel Services

Name	Authority
Vice President, Fuel Services	[redacted]
Gas Services Director	
Gas Operations Manager	
Gas Trading Manager	
Natural Gas Trader - Physical	
Natural Gas Trader - Financial	
Natural Gas Schedulers	
Coal Services Director	

APPENDIX E

SEGREGATION OF DUTIES

To ensure that risk management activities are properly carried out, certain functions will be separated. The following chart identifies these functions (depicted as **BOLD** bullet items) and their reporting process.



APPENDIX F
MARKET RISK MEASUREMENT

Approved Commodities	[redacted]
Electrical Power	
Natural Gas	
Coal Environmental Products Oil Products RECs	

Parametric VaR Methodology

Formula Components

Component	Symbol	Comments
Value at Risk	VaR	See Equation Below
Position	PSN	Given in Applicable Measurement Units
Daily Standard Deviation of Price Change	ΔP	Given in $/Applicable Measurement Units
Holding Period – Business Days	HP	Taken From Parameters Table Shown Below
Confidence Interval Multiplier	CI	For Example: CI = 1.65 for 95-% Confidence Interval

Equation

VaR = PSN * □P * Square Root of HP * CI

ParametersCommodity	Holding Period (HP)	Multiplier (CI)
Electric Power Term <= 1 Year Term > 1 Year	[redacted]	[redacted]
Natural Gas Term <= 1 Year Term > 1 Year		

APPENDIX F

STRESS TESTING METHODOLOGY

The purpose of stress testing is to generate percentage price changes for the forward curve that answer this question:

> If an extreme event occurs, what can we expect to happen to prices and the portfolio value?

The stress test is designed to capture the expected value of an extreme event as defined by an extreme value distribution. To differentiate, there is a downward and an upward stress test.
Specifically, the expected downward stress is calculated as:

$E[\Delta p/p \mid \Delta p/p < \Theta]$ = the Integral of f(x)xdx from negative infinity to Θ

and the expected upward stress is calculated as:

$E[\Delta p/p \mid \Delta p/p > \Theta]$ = the Integral of f(x)xdx from Θ to infinity

where Θ is the threshold that defines classification as an extreme event, f(x) is an extreme value distribution fitted to a specific contract, and x is a percentage price change.

Price Return Distribution	[redacted]
Holding Period	
Extreme Event Threshold	

Ad Hoc Stress Testing

Ad hoc stress testing will be performed as appropriate based on price scenarios determined using alternative methods including, but not limited to, the following:

- specific historical scenarios;
- rating agency defined price changes;
- analysis of out-of-the money option trading; and
- subjectively determined price changes.

APPENDIX G
NOTIFICATION LEVELS

Position Classification	Income Change	Notify
Secondary Objectives	[redacted]	
Secondary Objectives		
Secondary Objectives		

APPENDIX G
NOTIFICATION LEVELS

Position Classification	Income Change	Notify
All positions with mark-to-market changes immediately reflected in income (both primary and secondary activities)	[redacted]	
All positions with mark-to-market changes immediately reflected in income (both primary and secondary activities)		

APPENDIX G
NOTIFICATION LEVELS

Position Classification	Value-at-Risk	Notify
All positions, except hedges associated with a commission approved program which provides for its own limits and/or cost recovery	[redacted]	

NOTE: Recipients of notification events will only receive detailed information pertinent to their business needs, and any correspondence will be in compliance with the Separation Protocol.

APPENDIX G
NOTIFICATION LEVELS

Position Classification	Income Change	Notify
SPC Secondary Objectives	[redacted]	
SPC Secondary Objectives		
SPC Secondary Objectives		

Position Classification	Income Change	Notify
All SPC positions with mark-to-market changes immediately reflected in income	[redacted]	
All SPC positions with mark-to-market changes immediately reflected in income		

Position Classification	Value-at-Risk	Notify
All SPC positions	[redacted]	

APPENDIX H
MARKET RISK LIMITS

Net Open Position Limits

		Value –at- Risk Limit
Secondary Activities		[redacted]
All positions with marked-to-market changes immediately reflected in income		

NOTE: Although the value-at-risk limit applies to positions marked to market through income, VaR is calculated and monitored for all positions, and there are notification requirements as defined in Appendix G.

If such open position limits are exceeded, SCS Risk Control will calculate and equitably allocate the responsibilities to bring the positions back into compliance.

APPENDIX I
INCUMBENT LISTING; AUTHORIZED INDIVIDUALS

Southern Company Risk Oversight Committee

Title
CFO & CRO, Southern Company
Chairman, President, and CEO, Southern Company
EVP, President & CEO, SCS
EVP & COO, SCS
EVP, Southern Company & President & CEO, APC
EVP, Southern Company & President & CEO, GPC
EVP, Southern Company & President & CEO, MPC
EVP, Southern Company & President & CEO, Gulf
EVP, Southern Company & President & CEO, Southern Nuclear
EVP, Southern Company & President External Affairs
EVP, General Counsel, and Corporate Secretary, Southern Company
EVP, Finance & Treasurer – invited guest

Southern Company Risk Advisory & Controls Committee

Title
CFO & CRO, Southern Company
CFO, APC
CFO, GPC
CFO, Gulf Power Company
CFO, MPC
CFO, Operations
CFO, SPC
CFO, VP & Treasurer Southern Communications
VP Comptroller & Treasurer, SNC
Comptroller, CAO, & SVP, SCS
EVP Finance & Treasurer, SCS
VP & Associate General Counsel, SCS
Chief Audit Executive – invited guest

APPENDIX I
INCUMBENT LISTING; AUTHORIZED INDIVIDUALS

Southern Company Generation Risk Oversight Committee

Title
Compliance Officer & VP, SCS
EVP of E&CS, SCG
Chief Production Officer, SCG
Legal Counsel, Balch & Bingham – invited guest
CFO, Operations
Enterprise Risk Management Director
Internal Audit Representative – invited guest

Southern Power Risk Oversight Committee

Title
CFO, SPC
President, SPC
Chief Commercial Officer, SPC
Senior Production Officer, SPC
External & Regulatory Affairs VP, SPC

Southern Company Generation Energy Credit Committee

Title
Assistant Treasurer, SCS
VP, Fuel Services
VP, Commercial Operations & Services
Enterprise Risk Management Director
Energy Trading Manager – invited guest

APPENDIX I
INCUMBENT LISTING; AUTHORIZED INDIVIDUALS (continued)

Authorized Individuals

Title	Application / Role (3)	Approved Commodities								
		Electricity		Natural Gas						
		Energy	Trans.	Gas	Trans-port	Storage	Coal	Oil	Allow-ances	RECs
Southern Company Generation										
Energy Term Trading Mgr.	SCS GemTrader / Trader	X	X	(2)			(2)	(2)	(2)	(2)
Term Trader	SCS GemTrader / Trader	X	X	(2)			(2)	(2)	(2)	(2)
Trading Operations & Technical Svcs. Mgr.	SCS GemTrader/Public	(1)	(1)							
Hourly Trading Mgr.	SCS GemTrader / NextHour	X	X							
Energy Coordinator	SCS GemTrader / NextHour	X	X							
Scheduling Supervisor – Day Ahead	SCS GemTrader / Trader	X	X	(2)			(2)	(2)	(2)	(2)
Scheduling Supervisor – Hourly	SCS GemTrader / Trader	X	X	(2)			(2)	(2)	(2)	(2)
Scheduler	SCS GemTrader / Scheduler	(1)	X							
Trading Analyst	SCS GemTrader / TraderAnalyst	(1)	(1)							

Notes:
(1) Authority to make changes to transactions including entering transactions related to loss adjustments and full/partial requirements customers.
(2) Authority to direct a transaction.
(3) A complete list of approved individuals is located in the following Cool Compliance entities: SCS GemTrader, Trader, Deal Entry; Attaché; Attaché Emissions; Attaché Financials & Trading. Choose the appropriate role to see a complete list of authorized individuals.

APPENDIX I
INCUMBENT LISTING; AUTHORIZED INDIVIDUALS (continued)

Authorized Individuals

Title	Application / Role (3)	Approved Commodities								
		Electricity		Natural Gas						
		Energy	Trans	Gas	Trans-port	Storage	Coal	Oil	Allow-ances	RECs
SCS Fuel Services										
Gas Services, Director	Attache / Guest			X	X	X		X		
Gas Operations Mgr.	Attache / Front Office			X	X	X				
NG Buyer - Physical	Attache / Marketer			X	X	X				
Financial Trading Mgr.	Attache Financials & Trading / Fuel Trader			X				X		
NG Buyer - Financial	Attache Financials & Trading / Fuel Trader			X				X		
NG Scheduler	Attache / Front Office				X	X				
Coal & Transport Procure Manager	ComTrac / Fuel Procurement						X			
Emissions Trading Mgr	Attache Emissions / Emissions Trader								X	X
Emissions Trader	Attache Emissions / Emissions Trader								X	X

Title	Application / Role (3)	Approved Commodities								
		Electricity		Natural Gas						
		Energy	Trans.	Gas	Trans-port	Storage	Coal	Oil	Allow-ance	RECs
Southern Power Company										
Manager - Trading & Asset Management	SPC GemTrader / Trader	X	(2)	(2)			(2)	(2)	(2)	(2)
Asset Management	SPC GemTrader / Public			(2)						(2)
Term Trading Manager	SPC GemTrader / Trader	X	X	(2)			(2)	(2)	(2)	(2)
Term Trader	SPC GemTrader / Trader	X	X	(2)			(2)	(2)	(2)	(2)
Asset Manager	SPC GemTrader / Public			(2)	(2)	(2)				

Notes:

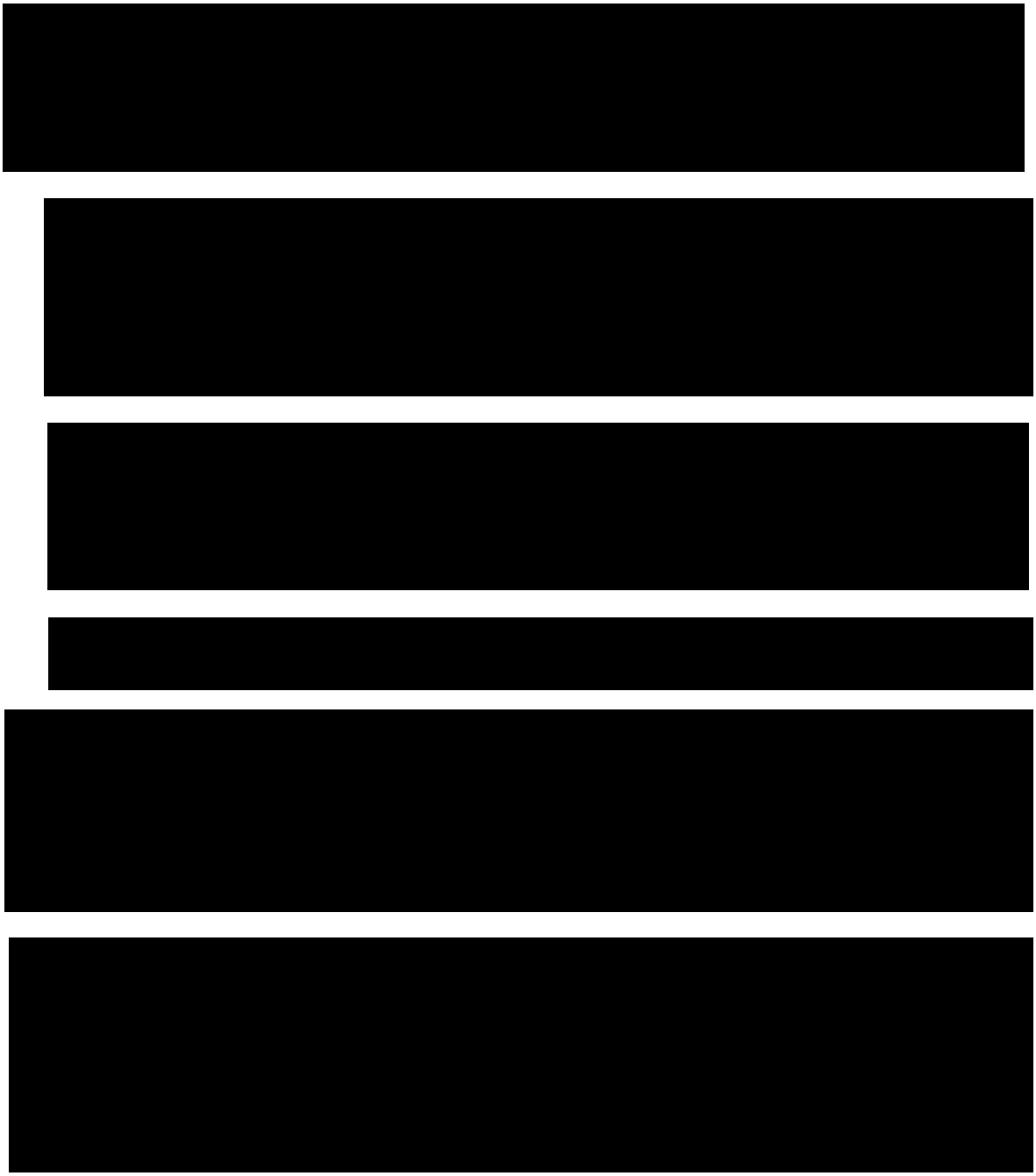
(1) Authority to make changes to transactions including entering transactions related to loss adjustments and full/partial requirements customers.

(2) Authority to direct a transaction.

(3) A complete list of approved individuals is located in one of the following Cool Compliance entities: SCS GemTrader, Trader, Deal Entry; Attaché; Attaché Emissions; Attaché Financials & Trading. Choose the appropriate role to see a complete list of authorized individuals.

APPENDIX J
ACCOUNTING AND TAX

FASB Accounting Standards Codification ("ASC") 815 Derivatives and Hedging, ASC 820 Fair Value Measurements and related GAAP standards are the primary pronouncements addressing hedge accounting and provides guidance for exchange-traded contracts.



APPENDIX K
EMPLOYEE ACKNOWLEDGMENT

I have been provided a copy of the Southern Company Energy Trading Risk Management Policy (RMP) and have had an opportunity to read and familiarize myself with its contents and understand the requirements that apply to my position.

I understand that the officers and Board of Directors of SCS place a very high priority on each employee adhering to the requirements, policies, and procedures described in the RMP and on the accurate tracking and reporting of levels and types of risks as described in the RMP.

I agree to comply with the policies, requirements, and procedures of the RMP as all or portions of the RMP apply to my position. I do not have any questions regarding or need to clarify any matters contained in the RMP. I understand that failure to comply with the RMP or associated or related policies can result in disciplinary actions up to and including termination of employment.

_____
Printed Name

_____
Signature

Date: _____ , 20__

Note, as an alternative to acquiring and maintaining a physical signature, employees will acknowledge the policy through Cool Compliance effective August 2012.

APPENDIX L
DEFINITIONS

Allowances	An authorization to emit chemical pollutants, including but not limited to sulfur dioxide, nitrous oxide, or greenhouse gases. These are usually traded in over-the-counter markets via brokers with one allowance permitting the emission of one ton of the pollutant.
Approved Business Objectives	Those business objectives defined in Appendix A which have been approved.
Approved Commodity	Those commodities listed in Appendix B which have been approved.
Authorities	All applicable limitations imposed on SCG RMP trading activities, and shall include, but not necessarily be limited to, authorized trading limits, daily loss exposure limits, maximum approved value at risk, income limits, and term limits.
Authorized Individuals	Employees whose position may involve: (1) the authority (or appearance of authority) to directly bind the Company to agreements with third parties; and/or (2) the authority (or appearance of authority), acting through its various brokers and other representatives, to the Company to exchange-traded futures and option contracts.
Approved Risk Management Instruments	Those instruments listed in Appendix C which have been approved.
Authorized Trading Limit	The levels set out in Appendix H. Such levels are expressed in dollars that establish boundaries for maximum value at risk due to changes in market prices.
Credit Policy	Southern Company Energy Trading Credit Risk Management Policy
Daily Portfolio Value	The net present value on a mark-to-market basis of yet to be performed transactions from all approved portfolios.
Financial Instruments	Futures, forwards, options, swaps, and other derivative or financial risk management transactions entered into to hedge price risks.

Forwards	An agreement to buy or sell a quantity of a product, at an agreed price, on a given date, with a specific counterparty. Forwards are typically trading in the over-the-counter (OTC) markets.
Futures	An agreement to buy or sell a quantity of a product, at an agreed price, on a given date, traded on an exchange, and cleared by a clearinghouse.
Hedging Strategy	A trading strategy intended to reduce risk.
Illiquid Market	A market characterized by wide bid/offer spreads, lack of transparency, and large movements in price after any sizable deal.
Mark to Market (MTM)	The value of a financial instrument, or risk book of such instruments, at current market rates, or prices of the underlying commodity.
Market Positions	Positions taken that are readily liquidated at a readily observable and transparent price.
Net Open Position	The sum of all open positions for the approved commodities on an equivalent basis.
Open Position	The difference between long positions and short positions in any given risk book.
Option	An instrument which provides the holder the right, but not the obligation, to sell to (or buy from) the option seller the underlying commodity at a specified price and time.
Originator	The lead individual responsible for negotiating the transaction with the counterparty.
P&L	Profit and loss
Premises	Southern Company Generation business office located in Birmingham, Alabama.
Products	Financial instruments and related transactions for approved commodities as dictated by usage.
Risk Book	The official record in which details of all transactions are maintained for valuing, monitoring, managing, and reporting said risk.

RMP	Risk Management Policy
Separation Protocol	The separation of SPC functions from the Southern Operating Companies (Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company) including information sharing and a separation of personnel in order to comply with a Federal Energy Regulatory Commission (FERC) Order.
SCS	Southern Company Services, Inc.
SPC	Southern Power Company
Swaps	An agreement to exchange net future cash flows.
Structured Transaction	Any negotiated transaction not readily traded in the market and the price of which is not easily validated.
Transactions	Futures, forwards, options, swaps, or other instruments conducted over-the-counter or via organized exchanges including long- and short-term agreements involving approved commodities or financial instruments.
Value at Risk (VaR)	The expected loss that will be incurred on the portfolio with a given level of confidence over a specified holding period, based on the distribution of price changes over a given historical observation period. (This is not an estimate of worst possible loss.)

Risk Management for Fuel and Wholesale Energy

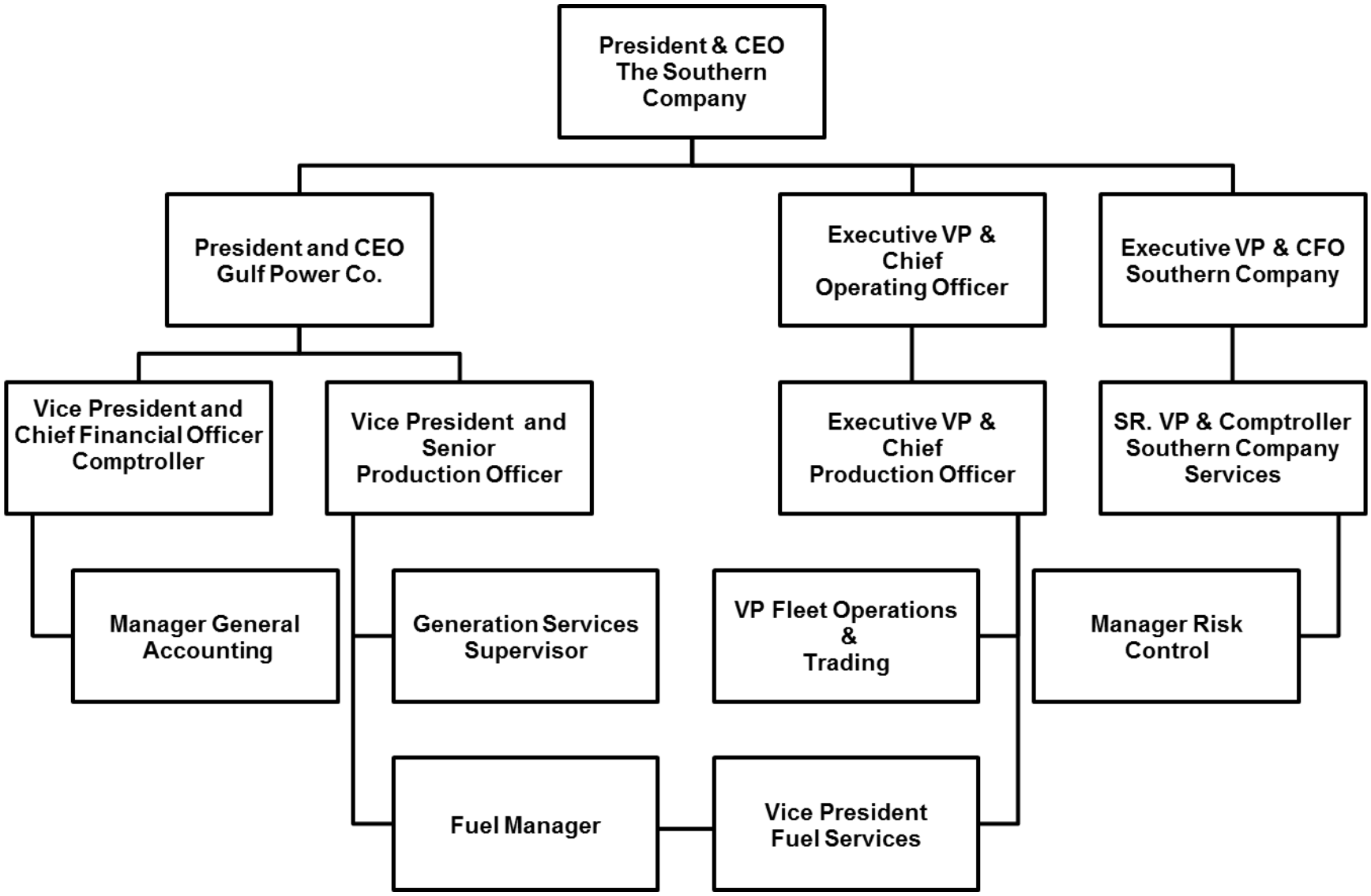


EXHIBIT NO. CSB-1

TABLE OF CONTENTS

FUEL AND PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

TITLE	DESCRIPTION	PAGE
Schedule 1	Calculation of Fuel and Purchased Power Actual True-up	2
Schedule CCA-1	Calculation of Capacity Actual True-up	3
Schedule CCA-2	Calculation of Capacity Over/(Under) Recovery	4
Schedule CCA-3	Calculation of Interest Provision on Capacity Over/(Under) Recovery	5
Schedule CCA-4	Capacity Costs	6
Appendix 1	Schedules A1 through A9 and A12 January 2015 through December 2015	7

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 44
PARTY: GULF POWER COMPANY – (DIRECT)
DESCRIPTION: C. S. Boyett CSB-1

Schedule 1

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
JANUARY 2015 - DECEMBER 2015

1. Estimated over/(under)-recovery for the period January 2015 - December 2015 (Schedule E-1B, Line 6 + 7 + 8, filed August 4, 2015) approved in FPSC Order No. PSC-15-0586-FOF-EI issued on December 23, 2015)	$ 11,285,334
2. Actual over/(under)-recovery for the period January 2015 - December 2015 (December 2015 Schedule A-2, page 2 of 3, "Period-to-Date", Lines 7 + 8 + 12, included in Appendix 1)	9,961,267
3. Amount to be refunded/(recovered) in the January 2017 - December 2017 projection period (Line 2 - Line 1)	$ (1,324,066)

Schedule CCA-1

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
JANUARY 2015 - DECEMBER 2015

1. Estimated over/(under)-recovery for the period January 2015 - December 2015 (Schedule CCE-1a, line 1, filed August 4, 2015 and approved in FPSC Order No. PSC-15-0586-FOF-EI issued on December 23, 2015)	$	910,906
2. Actual over/(under)-recovery for the period January 2015 - December 2015 (Schedule CCA-2, Line 10 + 11 + 14)		(54,861)
3. Amount to be refunded/(recovered) in the January 2017 - December 2017 projection period (Line 2 - Line 1)	$	(965,767)

Schedule CCA-2

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP AND INTEREST PROVISION
FOR THE PERIOD JANUARY 2015 - DECEMBER 2015

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1.	IIC Payments / (Receipts) ($)	(27,430)	(22,839)	(27,724)	(19,111)	(16,856)	(14,601)	(16,034)	(14,835)	(16,002)	(18,547)	(14,601)	(25,446)	(234,026)
2.	Other Capacity Payments / (Receipts)	7,414,958	7,414,958	7,414,958	7,414,229	7,414,229	7,437,788	7,386,742	7,386,742	7,386,742	7,386,742	7,386,547	7,386,547	88,831,164
3.	Transmission Revenue ($)	(11,858)	(23,711)	(17,766)	(12,768)	(12,573)	(12,274)	(11,020)	(12,464)	(12,729)	(12,484)	(22,541)	(9,804)	(171,992)
4.	Total Capacity Payments/(Receipts) (Line 1 + 2 + 3) ($)	7,375,670	7,368,408	7,369,468	7,382,350	7,384,800	7,410,894	7,359,689	7,359,443	7,358,011	7,355,711	7,349,405	7,351,297	88,425,147
5.	Jurisdictional %	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	
6.	Total Jurisdictional Recovery Amount (Line 4 * 5) ($)	7,159,671	7,152,621	7,153,650	7,166,155	7,168,533	7,193,863	7,144,157	7,143,919	7,142,529	7,140,296	7,134,175	7,136,010	85,835,579
7.	Jurisdictional Capacity Cost Recovery Revenues Net of Taxes ($)	6,764,549	6,446,397	5,813,032	6,103,818	7,518,166	8,580,320	9,567,140	9,127,789	7,648,741	6,145,248	5,682,851	5,781,260	85,179,310
8.	True-Up Provision ($)	50,114	50,116	50,116	50,116	50,116	50,116	50,116	50,116	50,116	50,116	50,116	50,116	601,390
9.	Jurisdictional Capacity Cost Recovery Revenue (Line 7 + 8) ($)	6,814,663	6,496,513	5,863,148	6,153,934	7,568,282	8,630,436	9,617,256	9,177,905	7,698,857	6,195,364	5,732,967	5,831,376	85,780,701
10.	Over/(Under) Recovery (Line 9 - 6) ($)	(345,008)	(656,108)	(1,290,502)	(1,012,221)	399,749	1,436,573	2,473,099	2,033,986	556,328	(944,932)	(1,401,208)	(1,304,634)	(54,878)
11.	Interest Provision ($)	(41)	(82)	(155)	(206)	(243)	(207)	(57)	125	260	245	128	(62)	(305)
12.	Beginning Balance True-Up & Interest Provision ($)	(291,657)	(686,820)	(1,393,126)	(2,733,899)	(3,796,120)	(3,446,730)	(2,080,480)	362,436	2,346,431	2,852,903	1,858,100	406,904	(291,657)
13.	True-Up Collected/(Refunded) ($)	(50,114)	(50,116)	(50,116)	(50,116)	(50,116)	(50,116)	(50,116)	(50,116)	(50,116)	(50,116)	(50,116)	(50,116)	(601,390)
14.	Adjustment	-	-	-	322	-	-	-	-	-	-	-	-	322
15.	End of Period Total Net True-Up (Lines 10 + 11 + 12 + 13 + 14) ($)	(686,820)	(1,393,126)	(2,733,899)	(3,796,120)	(3,446,730)	(2,080,480)	362,436	2,346,431	2,852,903	1,858,100	406,904	(947,908)	(947,908)
	Average Monthly Interest Rate	0.0063%	0.0079%	0.0075%	0.0063%	0.0067%	0.0075%	0.0079%	0.0092%	0.0100%	0.0104%	0.0113%	0.0229%	
	Commercial Paper Annual Rate 0.10%	0.10%	0.09%	0.09%	0.06%	0.10%	0.08%	0.11%	0.11%	0.13%	0.12%	0.15%	0.40%	
	Average Annual Rate	0.100%	0.095%	0.090%	0.075%	0.080%	0.090%	0.095%	0.110%	0.120%	0.125%	0.135%	0.275%	

Schedule CCA-3

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
FOR THE PERIOD JANUARY 2015 - DECEMBER 2015

	January	February	March	April	May	June	July	August	September	October	November	December	Total
1. Beginning True-Up Amount ($)	(291,657)	(686,620)	(1,393,126)	(2,733,899)	(3,796,120)	(3,446,730)	(2,060,480)	362,436	2,348,431	2,852,903	1,858,100	406,904	
2. Ending True-Up Amount Before Interest ($)	(686,779)	(1,393,044)	(2,733,744)	(3,795,592)	(3,446,487)	(2,060,273)	362,503	2,348,306	2,852,643	1,857,655	406,776	(947,846)	
3. Total Beginning & Ending True-Up Amount ($) (Lines 1 + 2)	(978,436)	(2,079,664)	(4,126,870)	(6,529,491)	(7,242,607)	(5,507,003)	(1,697,977)	2,708,742	5,199,074	4,710,758	2,264,876	(540,942)	
4. Average True-Up Amount ($)	(489,218)	(1,039,932)	(2,063,435)	(3,264,746)	(3,621,304)	(2,753,502)	(848,989)	1,354,371	2,599,537	2,355,379	1,132,438	(270,471)	
5. Interest Rate - First Day of Reporting Business Month	0.10%	0.10%	0.09%	0.09%	0.06%	0.10%	0.08%	0.11%	0.11%	0.13%	0.12%	0.15%	
6. Interest Rate - First Day of Subsequent Business Month	0.10%	0.09%	0.09%	0.06%	0.10%	0.08%	0.11%	0.11%	0.13%	0.12%	0.15%	0.40%	
7. Total Interest Rate (Lines 5 + 6)	0.20%	0.19%	0.18%	0.15%	0.16%	0.18%	0.19%	0.22%	0.24%	0.25%	0.27%	0.55%	
8. Average Interest Rate	0.100%	0.095%	0.090%	0.075%	0.080%	0.090%	0.095%	0.110%	0.120%	0.125%	0.135%	0.275%	
9. Monthly Average Interest Rate (1/12 of Line 8)	0.0083%	0.0079%	0.0075%	0.0063%	0.0067%	0.0075%	0.0079%	0.0092%	0.0100%	0.0104%	0.0113%	0.0229%	
10. Interest Provision For the Month (Lines 4 X 9) ($)	(41)	(82)	(155)	(206)	(243)	(207)	(67)	125	260	245	128	(62)	(305)

Docket No. 160001-EI
2015 Final True-Up Filing
Exhibit CSB-1, Page 5 of 202

Gulf Power Company
2015 Capacity Contracts

	Contract/Counterparty	Term Start	Term End [1]	Contract Type
3	Southern Intercompany Interchange	5/1/2007	5 Yr Notice	SES Opco
4	*PPAs*			
5	Shell Energy N.A. (U.S.), LP	11/2/2009	5/31/2023	Firm
6	*Other*			
7	Alabama Electric Cooperative	1/4/2015	7/20/2015	Other
8	Cargill Power, LLC	1/7/2015	11/23/2015	Other
9	South Carolina PSA	9/1/2003	-	Other
10	South Carolina Electric & Gas	1/2/2015	12/31/2015	Other
11	The Energy Authority	9/9/2015	10/25/2015	Other

	Capacity Costs ($)	January	February	March	April	May	June	July	August	September	October	November	December[2]	Total
13	Southern Intercompany Interchange	0	0	0	0	0	0	0	0	0	0	0	(8,431)	(8,431)
14	*PPAs*													
15	Shell Energy N.A. (U.S.), LP													
16														
17	*Other*													
18	Alabama Electric Cooperative				0	0	0		0	0	0	0	0	(35,623)
19	Cargill Power, LLC					0							0	18,040
20	South Carolina PSA													(39,792)
21	South Carolina Electric & Gas													(166,338)
22	The Energy Authority	0	0	0	0	0	0	0	0			0	0	(1,882)
23	Total	7,387,528	7,392,119	7,387,234	7,395,118	7,397,373	7,423,168	7,370,708	7,371,907	7,370,740	7,368,195	7,371,946	7,361,101	88,597,137

	Capacity MW	January	February	March	April	May	June	July	August	September	October	November	December[2]
25	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	(51.7)
26	*PPAs*												
27	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
28													
29	*Other*												
30	Alabama Electric Cooperative				0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0
31	Cargill Power, LLC					0.0							0.0
32	South Carolina PSA												
33	South Carolina Electric & Gas												
34	The Energy Authority	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			0.0	0.0

(1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.
(2) Southern Intercompany Interchange reserve sharing charge consists of prior month true-up only

APPENDIX 1

SCHEDULES A1 THROUGH A9 AND A12

JANUARY 2015 – DECEMBER 2015

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 150001-EI

MONTHLY FUEL FILING

January 2015

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JANUARY 2015

		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)	24,803,847	26,532,903	(1,729,056)	(6.52)	705,940,000	628,781,000	77,159,000	12.27	3.5136	4.2197	(0.71)	(16.73)
2	Hedging Settlement Costs (A2)	4,004,715	0	4,004,715	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	(90)	0	(90)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	28,808,472	26,532,903	2,275,569	8.58	705,940,000	628,781,000	77,159,000	12.27	4.0809	4.2197	(0.14)	(3.29)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	16,688,896	18,968,000	(2,279,104)	(12.02)	784,602,733	540,174,000	244,428,733	45.25	2.1271	3.5115	(1.38)	(39.42)
9	Energy Cost of Schedule E Economy Purch. (A9)	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	351,687	0	351,687	100.00	13,250,000	0	13,250,000	100.00	2.6542	0.0000	2.65	0.00
12	TOTAL COST OF PURCHASED POWER	17,040,583	18,968,000	(1,927,417)	(10.16)	797,852,733	540,174,000	257,678,733	47.70	2.1358	3.5115	(1.38)	(39.18)
13	Total Available MWH (Line 5 + Line 12)	45,849,055	45,500,903	348,152	0.77	1,503,792,733	1,168,955,000	334,837,733	28.64				
14	Fuel Cost of Economy Sales (A6)	(449,069)	(322,000)	(127,069)	39.46	(18,559,902)	(10,255,000)	(8,304,902)	80.98	(2.4196)	(3.1399)	0.72	22.94
15	Gain on Economy Sales (A6)	(51,245)	(35,000)	(16,245)	46.41	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(8,190,658)	(6,086,000)	(2,104,658)	34.58	(538,906,139)	(204,578,000)	(334,328,139)	163.42	(1.5199)	(2.9749)	1.46	48.91
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(8,690,972)	(6,443,000)	(2,247,972)	34.89	(557,466,041)	(214,833,000)	(342,633,041)	159.49	(1.5590)	(2.9991)	1.44	48.02
18	Net Inadvertant Interchange	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	37,158,083	39,057,903	(1,899,820)	(4.86)	946,326,692	954,122,000	(7,795,308)	(0.82)	3.9266	4.0936	(0.17)	(4.08)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	75,418	77,873	(2,455)	(3.15)	1,920,704	1,902,300	18,404	0.97	3.9266	4.0936	(0.17)	(4.08)
22	T & D Losses *	1,921,347	2,043,185	(121,838)	(5.96)	48,931,575	49,911,700	(980,125)	(1.96)	3.9266	4.0936	(0.17)	(4.08)
23	TERRITORIAL KWH SALES	37,158,083	39,057,903	(1,899,820)	(4.86)	895,474,413	902,308,000	(6,833,587)	(0.76)	4.1495	4.3287	(0.18)	(4.14)
24	Wholesale KWH Sales	1,141,942	1,301,214	(159,272)	(12.24)	27,519,518	30,060,000	(2,540,482)	(8.45)	4.1496	4.3287	(0.18)	(4.14)
25	Jurisdictional KWH Sales	36,016,141	37,756,689	(1,740,548)	(4.61)	867,954,895	872,248,000	(4,293,105)	(0.49)	4.1495	4.3287	(0.18)	(4.14)
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	36,070,165	37,813,324	(1,743,159)	(4.61)	867,954,895	872,248,000	(4,293,105)	(0.49)	4.1558	4.3352	(0.18)	(4.14)
28	TRUE-UP	3,996,370	3,996,370	0	0.00	867,954,895	872,248,000	(4,293,105)	(0.49)	0.4604	0.4582	0.00	0.48
29	TOTAL JURISDICTIONAL FUEL COST	40,066,535	41,809,694	(1,743,159)	(4.17)	867,954,895	872,248,000	(4,293,105)	(0.49)	4.6162	4.7934	(0.18)	(3.70)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.6195	4.7969	(0.18)	(3.70)
32	GPIF Reward / (Penalty)	210,330	210,330	0	0.00	867,954,895	872,248,000	(4,293,105)	(0.49)	0.0242	0.0241	0.00	0.41
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.6437	4.8210	(0.18)	(3.68)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.644	4.821		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: JANUARY 2015

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 24,803,847
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	(90)
4	Hedging Settlement Costs	Schedule A-2, Line A-5	4,004,715
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	16,688,896
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	351,687
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(8,690,972)
10	Total Fuel and Net Power Transactions		$ 37,158,083

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JANUARY 2015
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)	24,803,847	26,532,903	(1,729,056)	(6.52)	705,940,000	628,781,000	77,159,000	12.27	3.5136	4.2197	(0.71)	(16.73)
2	Hedging Settlement Costs (A2)	4,004,715	0	4,004,715	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	(90)	0	(90)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	28,808,472	26,532,903	2,275,569	8.58	705,940,000	628,781,000	77,159,000	12.27	4.0809	4.2197	(0.14)	(3.29)
6	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
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	16,688,896	18,968,000	(2,279,104)	(12.02)	784,602,733	540,174,000	244,428,733	45.25	2.1271	3.5115	(1.38)	(39.42)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	351,687	0	351,687	100.00	13,250,000	0	13,250,000	100.00	2.6542	0.0000	2.65	0.00
12	TOTAL COST OF PURCHASED POWER	17,040,583	18,968,000	(1,927,417)	(10.16)	797,852,733	540,174,000	257,678,733	47.70	2.1358	3.5115	(1.38)	(39.18)
13	Total Available MWH (Line 5 + Line 12)	45,849,055	45,500,903	348,152	0.77	1,503,792,733	1,168,955,000	334,837,733	28.64				
14	Fuel Cost of Economy Sales (A6)	(449,069)	(322,000)	(127,069)	39.46	(18,559,902)	(10,255,000)	(8,304,902)	80.98	(2.4198)	(3.1399)	0.72	22.94
15	Gain on Economy Sales (A6)	(51,245)	(35,000)	(16,245)	46.41	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(8,190,658)	(6,086,000)	(2,104,658)	34.58	(538,906,139)	(204,578,000)	(334,328,139)	163.42	(1.5199)	(2.9749)	1.46	48.91
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(8,690,972)	(6,443,000)	(2,247,972)	34.89	(557,466,041)	(214,833,000)	(342,633,041)	159.49	(1.5590)	(2.9991)	1.44	48.02
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	37,158,083	39,057,903	(1,899,820)	(4.86)	946,326,692	954,122,000	(7,795,308)	(0.82)	3.9266	4.0936	(0.17)	(4.08)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	75,418	77,873	(2,455)	(3.15)	1,920,704	1,902,300	18,404	0.97	3.9266	4.0936	(0.17)	(4.08)
22	T & D Losses *	1,921,347	2,043,185	(121,838)	(5.96)	48,931,575	49,911,700	(980,125)	(1.96)	3.9266	4.0936	(0.17)	(4.08)
23	TERRITORIAL KWH SALES	37,158,083	39,057,903	(1,899,820)	(4.86)	895,474,413	902,308,000	(6,833,587)	(0.76)	4.1495	4.3287	(0.18)	(4.14)
24	Wholesale KWH Sales	1,141,942	1,301,214	(159,272)	(12.24)	27,519,518	30,060,000	(2,540,482)	(8.45)	4.1496	4.3287	(0.18)	(4.14)
25	Jurisdictional KWH Sales	36,016,141	37,756,689	(1,740,548)	(4.61)	867,954,895	872,248,000	(4,293,105)	(0.49)	4.1495	4.3287	(0.18)	(4.14)
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	36,070,165	37,813,324	(1,743,159)	(4.61)	867,954,895	872,248,000	(4,293,105)	(0.49)	4.1558	4.3352	(0.18)	(4.14)
28	TRUE-UP	3,996,370	3,996,370	0	0.00	867,954,895	872,248,000	(4,293,105)	(0.49)	0.4604	0.4582	0.00	0.48
29	TOTAL JURISDICTIONAL FUEL COST	40,066,535	41,809,694	(1,743,159)	(4.17)	867,954,895	872,248,000	(4,293,105)	(0.49)	4.6162	4.7934	(0.18)	(3.70)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.8195	4.7969	(0.18)	(3.70)
32	GPIF Reward / (Penalty)	210,330	210,330	0	0.00	867,954,895	872,248,000	(4,293,105)	(0.49)	0.0242	0.0241	0.00	0.41
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.6437	4.8210	(0.18)	(3.68)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.644	4.821		

* 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: JANUARY 2015

		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	24,571,634.92	26,324,352	(1,752,717.08)	(6.66)	24,571,634.92	26,324,352	(1,752,717.08)	(6.66)
1a	Other Generation	232,212.00	208,551	23,661.00	11.35	232,212.00	208,551	23,661.00	11.35
2	Fuel Cost of Power Sold	(8,690,972.15)	(6,443,000)	(2,247,972.15)	(34.89)	(8,690,972.15)	(6,443,000)	(2,247,972.15)	(34.89)
3	Fuel Cost - Purchased Power	16,688,896.60	18,968,000	(2,279,103.40)	(12.02)	16,688,896.60	18,968,000	(2,279,103.40)	(12.02)
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	351,686.73	0	351,686.73	100.00	351,686.73	0	351,686.73	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	4,004,715.00	0	4,004,715.00	100.00	4,004,715.00	0	4,004,715.00	100.00
6	Total Fuel & Net Power Transactions	37,158,173.10	39,057,903	(1,899,729.90)	(4.86)	37,158,173.10	39,057,903	(1,899,729.90)	(4.86)
7	AdjustmentsTo Fuel Cost*	(90.11)	0	(90.11)	100.00	(90.11)	0	(90.11)	100.00
8	Adj. Total Fuel & Net Power Transactions	37,158,082.99	39,057,903	(1,899,820.01)	(4.86)	37,158,082.99	39,057,903	(1,899,820.01)	(4.86)
B.	*KWH Sales*								
1	Jurisdictional Sales	867,954,895	872,248,000	(4,293,105)	(0.49)	867,954,895	872,248,000	(4,293,105)	(0.49)
2	Non-Jurisdictional Sales	27,519,518	30,060,000	(2,540,482)	(8.45)	27,519,518	30,060,000	(2,540,482)	(8.45)
3	Total Territorial Sales	895,474,413	902,308,000	(6,833,587)	(0.76)	895,474,413	902,308,000	(6,833,587)	(0.76)
4	Juris. Sales as % of Total Terr. Sales	96.9268	96.6685	0.2583	0.27	96.9268	96.6685	0.2583	0.27

**(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: JANUARY 2015

		CURRENT MONTH				PERIOD - TO - DATE			
		$		*DIFFERENCE*		$		*DIFFERENCE*	
C.	*True-up Calculation*	ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
1	Jurisdictional Fuel Revenue	36,716,609.07	37,786,489	(1,069,879.95)	(2.83)	36,716,609.07	37,786,489	(1,069,879.95)	(2.83)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(3,996,370.00)	3,996,370	(7,992,740.00)	(200.00)	(3,996,370.00)	3,996,370	(7,992,740.00)	(200.00)
2b	Incentive Provision	(210,175.00)	(210,175)	0.00	0.00	(210,175.00)	(210,175)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	32,510,064.07	41,572,684	(9,062,619.93)	(21.80)	32,510,064.07	41,572,684	(9,062,619.93)	(21.80)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	37,158,082.99	39,057,903	(1,899,820.01)	(4.86)	37,158,082.99	39,057,903	(1,899,820.01)	(4.86)
5	Juris. Sales % of Total KWH Sales (Line B4)	96.9268	96.6685	0.2583	0.27	96.9268	96.6685	0.2583	0.27
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	36,070,164.99	37,813,324	(1,743,159.01)	(4.61)	36,070,164.99	37,813,324	(1,743,159.01)	(4.61)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(3,560,100.92)	3,759,360	(7,319,460.92)	194.70	(3,560,100.92)	3,759,360	(7,319,460.92)	194.70
8	Interest Provision for the Month	(3,291.25)	(3,990)	698.75	17.51	(3,291.25)	(3,990)	698.75	17.51
9	Beginning True-Up & Interest Provision	(39,871,741.42)	(47,956,495)	8,084,753.58	16.86	(39,871,741.42)	(47,956,495)	8,084,753.58	16.86
10	True-Up Collected / (Refunded)	3,996,370.00	(3,996,370)	7,992,740.00	(200.00)	3,996,370.00	(3,996,370)	7,992,740.00	(200.00)
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(39,438,763.59)	(48,197,495)	8,758,731.41	18.17	(39,438,763.59)	(48,197,495)	8,758,731.41	18.17
12	Adjustment	0.00	0	0.00	0.00	0.00	0	0.00	0.00
13	End of Period - Total Net True-Up	(39,438,763.59)	(48,197,495)	8,758,731.41	18.17	(39,438,763.59)	(48,197,495)	8,758,731.41	18.17

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2015

		CURRENT MONTH			
		$		*DIFFERENCE*	
D.	*Interest Provision*	**ACTUAL**	**ESTIMATED**	**AMOUNT ($)**	**%**
1	BeginningTrue-Up Amount (C9)	(39,871,741.42)	(47,956,495)	8,084,753.58	(16.86)
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	(39,435,472.34)	(48,193,505)	8,758,032.66	(18.17)
3	Total of Beginning & Ending True-Up Amts.	(79,307,213.76)	(96,150,000)	16,842,786.24	(17.52)
4	Average True-Up Amount	(39,653,606.88)	(48,075,000)	8,421,393.12	(17.52)
	Interest Rate				
5	1st Day of Reporting Business Month	0.10	0.10	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.10	0.10	0.0000	
7	Total (D5+D6)	0.20	0.20	0.0000	
8	Annual Average Interest Rate	0.10	0.10	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0083	0.0083	0.0000	
10	Interest Provision (D4*D9)	(3,291.25)	(3,990)	698.75	(17.51)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0015		

Docket No. 160001-EI
2015 Final True-Up Filing
Exhibit CSB-1, Page 14 of 202

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2015

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	221,431	136,749	84,682	61.93	221,431	136,749	84,682	61.93
2	COAL	14,351,629	14,959,242	(607,613)	(4.06)	14,351,629	14,959,242	(607,613)	(4.06)
3	GAS	9,813,210	11,146,061	(1,332,850)	(11.96)	9,813,210	11,146,061	(1,332,850)	(11.96)
4	GAS (B.L.)	267,158	227,536	39,622	17.41	267,158	227,536	39,622	17.41
5	LANDFILL GAS	62,531	63,315	(784)	(1.24)	62,531	63,315	(784)	(1.24)
6	OIL - C.T.	87,888	0	87,888	100.00	87,888	0	87,888	100.00
7	TOTAL ($)	24,803,847	26,532,903	(1,729,056)	(6.52)	24,803,847	26,532,903	(1,729,056)	(6.52)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	335,790	339,668	(3,878)	(1.14)	335,790	339,668	(3,878)	(1.14)
10	GAS	367,674	287,013	80,661	28.10	367,674	287,013	80,661	28.10
11	LANDFILL GAS	2,084	2,100	(16)	(0.76)	2,084	2,100	(16)	(0.76)
12	OIL - C.T.	392	0	392	100.00	392	0	392	100.00
13	TOTAL (MWH)	705,940	628,781	77,159	12.27	705,940	628,781	77,159	12.27
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	2,428	1,091	1,337	122.55	2,428	1,091	1,337	122.55
15	COAL (TONS)	160,647	159,057	1,590	1.00	160,647	159,057	1,590	1.00
16	GAS (MCF) (1)	2,526,251	1,936,986	589,265	30.42	2,526,251	1,936,986	589,265	30.42
17	OIL - C.T. (BBL)	795	0	795	100.00	795	0	795	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	3,716,738	3,770,293	(53,555)	(1.42)	3,716,738	3,770,293	(53,555)	(1.42)
19	GAS - Generation (1)	2,532,293	1,936,986	595,307	30.73	2,532,293	1,936,986	595,307	30.73
20	OIL - C.T.	4,635	0	4,635	100.00	4,635	0	4,635	100.00
21	TOTAL (MMBTU)	6,253,665	5,707,279	546,386	9.57	6,253,665	5,707,279	546,386	9.57
	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	47.56	54.02	(6.46)	(11.96)	47.57	54.02	(6.45)	(11.94)
24	GAS	52.08	45.65	6.43	14.09	52.08	45.65	6.43	14.09
25	LANDFILL GAS	0.30	0.33	(0.03)	(9.09)	0.30	0.33	(0.03)	(9.09)
26	OIL - C.T.	0.06	0.00	0.06	100.00	0.05	0.00	0.05	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)	91.19	125.34	(34.15)	(27.25)	91.19	125.34	(34.15)	(27.25)
29	COAL ($/TON)	89.34	94.05	(4.71)	(5.01)	89.34	94.05	(4.71)	(5.01)
30	GAS ($/MCF) (1)	3.90	5.76	(1.86)	(32.29)	3.90	5.76	(1.86)	(32.29)
31	OIL - C.T. ($/BBL)	110.55	0.00	110.55	100.00	110.55	0.00	110.55	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	3.99	4.06	(0.07)	(1.72)	3.99	4.06	(0.07)	(1.72)
33	GAS - Generation (1)	3.78	5.65	(1.87)	(33.10)	3.78	5.65	(1.87)	(33.10)
34	OIL - C.T.	18.96	0.00	18.96	100.00	18.96	0.00	18.96	100.00
35	TOTAL ($/MMBTU)	3.92	4.60	(0.68)	(14.78)	3.92	4.60	(0.68)	(14.78)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	11,069	11,100	(31)	(0.28)	11,069	11,100	(31)	(0.28)
37	GAS - Generation (1)	7,011	6,886	125	1.82	7,011	6,886	125	1.82
38	OIL - C.T.	11,823	0	11,823	100.00	11,823	0	11,823	100.00
39	TOTAL (BTU/KWH)	8,968	9,191	(223)	(2.43)	8,968	9,191	(223)	(2.43)
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	4.42	4.51	(0.09)	(2.00)	4.42	4.51	(0.09)	(2.00)
41	GAS	2.67	3.88	(1.21)	(31.19)	2.67	3.88	(1.21)	(31.19)
42	LANDFILL GAS	3.00	3.02	(0.02)	(0.66)	3.00	3.02	(0.02)	(0.66)
43	OIL - C.T.	22.42	0.00	22.42	100.00	22.42	0.00	22.42	100.00
44	TOTAL (¢/KWH)	3.51	4.22	(0.71)	(16.82)	3.51	4.22	(0.71)	(16.82)

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: JANUARY 2015

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2015	(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	18,774	33.6	56 2	64.8	10,979	Coal	8,909	11,568	206,121	822,197	4.38	92.29
2				0					Gas-G	0	1,020	0	0	0.00	0.00
3									Gas-S	28,900	1,020	29,478	127,825		4.42
4									Oil-S	54	137,660	311	6,885		127.50
5	Crist 5		75	19,000	34.1	84.5	69.5	10,601	Coal	8,579	11,739	201,417	791,735	4.17	92.29
6				-					Gas-G	0	1,020	0	0	0.00	0.00
7									Gas-S	19,162	1,020	19,545	84,753		4.42
8									Oil-S	46	137,660	268	5,923		127.87
9	Crist 6		299	26,429	11.9	99.9	54.6	12,031	Coal	13,454	11,817	317,972	1,241,635	4.70	92.29
10				0					Gas-G	1,459	1,020	1,488	6,453	0.00	0.00
11									Gas-S	12,339	1,020	12,587	54,580		4.42
12									Oil-S	1	137,660	6	123		123.00
13	Crist 7		475	178,627	50.5	96.8	53.9	10,213	Coal	79,304	11,502	1,824,298	7,318,720	4.10	92.29
14				0					Gas-G	17,778	1,020	18,133	78,631	0.00	4.42
15									Gas-S	0	1,020	0	0		0.00
16									Oil-S	26	137,660	153	3,380		130.00
17	Scholz 1		46	(269)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	0	0	0		0.00
19	Scholz 2		46	(193)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	0	0	0		0.00
21	Smith 1		162	37,693	31.3	94.0	47.6	11,060	Coal	18,734	11,126	416,869	1,637,147	4.34	87.39
22									Oil-S	785	138,820	4,575	64,238		81.83
23	Smith 2		195	32,485	22.4	100.0	43.5	11,612	Coal	16,963	11,119	377,232	1,482,421	4.56	87.39
24									Oil-S	287	138,820	1,675	23,521		81.95
25	Smith 3		584	359,330	82.7	99.6	91.0	6,993	Gas-G	2,446,613	1,027	2,512,672	9,495,914	2.64	3.88
26	Smith A	(2)	40	392	1.3	100.0	100.9	11,824	Oil	795	138,718	4,635	87,888	22.42	110.55
27	Other Generation			6,506									232,212	3.57	0.00
28	Perdido			2,084					Landfill Gas				62,531	3.00	0.00
29	Daniel 1	(1)	255	10,149	5.3	51.5	35.8	11,878	Coal	5,529	10,902	120,546	399,248	3.93	72.21
30									Oil-S	757	138,623	4,408	72,318		95.53
31	Daniel 2	(1)	255	14,933	7.9	71.0	40.4	11,821	Coal	9,175	9,620	176,530	662,585	4.44	72.22
32									Oil-S	472	138,623	2,746	45,043		95.43
33	Total		2,507	705,940	37.8	89.2	57.7	8,968				6,253,665	24,807,906	3.51	

Notes & Adjust.: (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

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.	(4,059)	
	Recoverable Fuel	24,803,847	3.51

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2015

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES :*								
2	UNITS (BBL)	2,249	1,091	1,158	106.14	2,249	1,091	1,158	106.14
3	UNIT COST ($/BBL)	68.76	122.72	(53.96)	(43.97)	68.76	122.72	(53.96)	(43.97)
4	AMOUNT ($)	154,643	133,890	20,753	15.50	154,643	133,890	20,753	15.50
5	*BURNED :*								
6	UNITS (BBL)	2,465	1,091	1,374	125.94	2,465	1,091	1,374	125.94
7	UNIT COST ($/BBL)	91.18	125.34	(34.16)	(27.25)	91.18	125.34	(34.16)	(27.25)
8	AMOUNT ($)	224,755	136,749	88,006	64.36	224,755	136,749	88,006	64.36
9	*ENDING INVENTORY :*								
10	UNITS (BBL)	6,781	7,166	(385)	(5.37)	6,781	7,166	(385)	(5.37)
11	UNIT COST ($/BBL)	110.14	126.40	(16.26)	(12.86)	110.14	126.40	(16.26)	(12.86)
12	AMOUNT ($)	746,870	905,818	(158,948)	(17.55)	746,870	905,818	(158,948)	(17.55)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES :*								
15	UNITS (TONS)	197,891	125,631	72,260	57.52	197,891	125,631	72,260	57.52
16	UNIT COST ($/TON)	86.23	79.10	7.13	9.01	86.23	79.10	7.13	9.01
17	AMOUNT ($)	17,064,783	9,937,547	7,127,236	71.72	17,064,783	9,937,547	7,127,236	71.72
18	*BURNED :*								
19	UNITS (TONS)	160,647	159,057	1,590	1.00	160,647	159,057	1,590	1.00
20	UNIT COST ($/TON)	89.36	94.05	(4.69)	(4.99)	89.36	94.05	(4.69)	(4.99)
21	AMOUNT ($)	14,355,688	14,959,242	(603,554)	(4.03)	14,355,688	14,959,242	(603,554)	(4.03)
22	*ENDING INVENTORY :*								
23	UNITS (TONS)	593,706	470,725	122,981	26.13	593,706	470,725	122,981	26.13
24	UNIT COST ($/TON)	81.07	78.52	2.55	3.25	81.07	78.52	2.55	3.25
25	AMOUNT ($)	48,134,469	36,962,021	11,172,448	30.23	48,134,469	36,962,021	11,172,448	30.23
26	DAYS SUPPLY	29	23	6	26.09				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES :*								
28	UNITS (MMBTU)	2,505,793	1,956,986	548,807	28.04	2,505,793	1,956,986	548,807	28.04
29	UNIT COST ($/MMBTU)	3.64	5.71	(2.07)	(36.25)	3.64	5.71	(2.07)	(36.25)
30	AMOUNT ($)	9,120,870	11,165,046	(2,044,176)	(18.31)	9,120,870	11,165,046	(2,044,176)	(18.31)
31	*BURNED :*								
32	UNITS (MMBTU)	2,593,903	1,956,986	636,917	32.55	2,593,903	1,956,986	636,917	32.55
33	UNIT COST ($/MMBTU)	3.80	5.71	(1.91)	(33.45)	3.80	5.71	(1.91)	(33.45)
34	AMOUNT ($)	9,847,407	11,165,046	(1,317,639)	(11.80)	9,847,407	11,165,046	(1,317,639)	(11.80)
35	*ENDING INVENTORY :*								
36	UNITS (MMBTU)	953,232	0	953,232	100.00	953,232	0	953,232	100.00
37	UNIT COST ($/MMBTU)	3.78	0.00	3.78	100.00	3.78	0.00	3.78	100.00
38	AMOUNT ($)	3,602,179	0	3,602,179	100.00	3,602,179	0	3,602,179	100.00
	OTHER - C.T. OIL								
39	*PURCHASES :*								
40	UNITS (BBL) *	894	0	894	100.00	894	0	894	100.00
41	UNIT COST ($/BBL)	68.86	0.00	68.86	100.00	68.86	0.00	69.00	100.00
42	AMOUNT ($)	61,561	0	61,561	100.00	61,561	0	61,561	100.00
43	*BURNED :*								
44	UNITS (BBL)	795	0	795	100.00	795	0	795	100.00
45	UNIT COST ($/BBL)	110.55	0.00	110.55	100.00	110.55	0.00	110.55	100.00
46	AMOUNT ($)	87,888	0	87,888	100.00	87,888	0	87,888	100.00
47	*ENDING INVENTORY :*								
48	UNITS (BBL)	7,157	7,143	14	0.20	7,157	7,143	14	0.20
49	UNIT COST ($/BBL)	110.48	117.59	(7.11)	(6.05)	110.48	117.59	(7.11)	(6.05)
50	AMOUNT ($)	790,700	839,922	(49,222)	(5.86)	790,700	839,922	(49,222)	(5.86)
51	DAYS SUPPLY	3	3	0	0.00				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2015

			CURRENT MONTH						
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
				KWH		(a)	(b)		
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	¢ / KWH FUEL COST	¢ / KWH TOTAL COST	(5) x (6)(a) TOTAL $ FOR FUEL ADJ.	(5) x (6)(b) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		204,578,000	0	204,578,000	2.97	3.36	6,086,000	6,865,000
2	Various	Economy Sales	10,255,000	0	10,255,000	3.14	3.45	322,000	354,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	35,000	35,000
4	TOTAL ESTIMATED SALES		214,833,000	0	214,833,000	3.00	3.38	6,443,000	7,254,000
	ACTUAL								
5	Southern Company Interchange		327,752,904	0	327,752,904	2.63	2.87	8,612,068	9,391,969
6	A.E.C.	External	8,729,320	0	8,729,320	2.46	2.96	215,105	258,773
7	AECI	External	383,996	0	383,996	2.34	2.93	8,999	11,261
8	AEP	External	0	0	0	0.00	0.00	0	0
9	CALPINE	External	0	0	0	0.00	0.00	0	0
10	CARGILE	External	150,221	0	150,221	2.78	2.95	4,182	4,434
11	DUKE PWR	External	621,895	0	621,895	2.26	3.49	14,062	21,678
12	EAGLE EN	External	384,988	0	384,988	2.08	2.78	8,006	10,690
13	ENDURE	External	6,632	0	6,632	2.11	3.50	140	232
14	EXELON	External	134,367	0	134,367	2.25	3.05	3,029	4,094
15	FPC	External	85,820	0	85,820	1.99	2.83	1,707	2,425
16	FPL	External	0	0	0	0.00	0.00	0	0
17	JPMVEC	External	30,178	0	30,178	2.11	2.93	635	884
18	MISO	External	684,895	0	684,895	1.96	2.76	13,422	18,906
19	MORGAN	External	524,528	0	524,528	3.21	2.86	16,821	15,024
20	NCEMC	External	194,516	0	194,516	3.18	3.28	6,177	6,387
21	NRG	External	0	0	0	0.00	0.00	0	0
22	OPC	External	292,675	0	292,675	2.56	3.71	7,479	10,846
23	ORLANDO	External	9,948	0	9,948	2.81	4.20	280	418
24	PJM	External	1,657,580	0	1,657,580	2.48	3.40	41,100	56,295
25	SCE&G	External	917,352	0	917,352	2.88	3.45	26,399	31,606
26	SEC	External	36,476	0	36,476	2.97	3.48	1,085	1,270
27	SEPA	External	1,224,944	0	1,224,944	2.10	3.04	25,731	37,242
28	SPP	External	0	0	0	0.00	0.00	0	0
29	TAL	External	0	0	0	0.00	0.00	0	0
30	TEA	External	1,968,952	0	1,968,952	2.15	3.09	42,290	60,750
31	TECO	External	29,847	0	29,847	2.31	3.43	690	1,025
32	TENASKA	External	0	0	0	0.00	0.00	0	0
33	TVA	External	119,380	0	119,380	2.73	3.64	3,258	4,347
34	WRI	External	371,392	0	371,392	2.28	2.69	8,474	9,975
35	Less: Flow-Thru Energy		(17,641,555)	0	(17,641,555)	2.39	2.39	(421,410)	(421,410)
36	SEPA		1,298,088	1,298,088	0	0.00	0.00	0	0
37	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	51,245	51,245
38	Other transactions including adj.		227,496,702	194,294,618	33,202,084	0.00	0.00	0	0
39	TOTAL ACTUAL SALES		557,466,041	195,592,706	361,873,335	1.56	1.71	8,690,972	9,539,123
40	Difference in Amount		342,633,041	195,592,706	147,040,335	(1.44)	(1.67)	2,247,972	2,285,123
41	Difference in Percent		159.49	0.00	68.44	(48.00)	(49.41)	34.89	31.50

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 37

SCHEDULE A-6
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POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2015

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		204,578,000	0	204,578,000	2.97	3.36	6,086,000	6,865,000
2	Various	Economy Sales	10,255,000	0	10,255,000	3.14	3.45	322,000	354,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	35,000	35,000
4	TOTAL ESTIMATED SALES		214,833,000	0	214,833,000	3.00	3.38	6,443,000	7,254,000
	ACTUAL								
5	Southern Company Interchange		327,752,904	0	327,752,904	2.63	2.87	8,612,068	9,391,969
6	A.E.C.	External	8,729,320	0	8,729,320	2.46	2.96	215,105	258,773
7	AECI	External	383,996	0	383,996	2.34	2.93	8,999	11,261
8	AEP	External	0	0	0	0.00	0.00	0	0
9	CALPINE	External	0	0	0	0.00	0.00	0	0
10	CARGILE	External	150,221	0	150,221	2.78	2.95	4,182	4,434
11	DUKE PWR	External	621,895	0	621,895	2.26	3.49	14,062	21,678
12	EAGLE EN	External	384,988	0	384,988	2.08	2.78	8,006	10,690
13	ENDURE	External	6,632	0	6,632	2.11	3.50	140	232
14	EXELON	External	134,367	0	134,367	2.25	3.05	3,029	4,094
15	FPC	External	85,820	0	85,820	1.99	2.83	1,707	2,425
16	FPL	External	0	0	0	0.00	0.00	0	0
17	JPMVEC	External	30,178	0	30,178	2.11	2.93	635	884
18	MISO	External	684,895	0	684,895	1.96	2.76	13,422	18,906
19	MORGAN	External	524,528	0	524,528	3.21	2.86	16,821	15,024
20	NCEMC	External	194,516	0	194,516	3.18	3.28	6,177	6,387
21	NRG	External	0	0	0	0.00	0.00	0	0
22	OPC	External	292,675	0	292,675	2.56	3.71	7,479	10,846
23	ORLANDO	External	9,948	0	9,948	2.81	4.20	280	418
24	PJM	External	1,657,580	0	1,657,580	2.48	3.40	41,100	56,295
25	SCE&G	External	917,352	0	917,352	2.88	3.45	26,399	31,606
26	SEC	External	36,476	0	36,476	2.97	3.48	1,085	1,270
27	SEPA	External	1,224,944	0	1,224,944	2.10	3.04	25,731	37,242
28	SPP	External	0	0	0	0.00	0.00	0	0
29	TAL	External	0	0	0	0.00	0.00	0	0
30	TEA	External	1,968,952	0	1,968,952	2.15	3.09	42,290	60,750
31	TECO	External	29,847	0	29,847	2.31	3.43	690	1,025
32	TENASKA	External	0	0	0	0.00	0.00	0	0
33	TVA	External	119,380	0	119,380	2.73	3.64	3,258	4,347
34	WRI	External	371,392	0	371,392	2.28	2.69	8,474	9,975
35	Less: Flow-Thru Energy		(17,641,555)	0	(17,641,555)	2.39	2.39	(421,410)	(421,410)
36	SEPA		1,298,088	1,298,088	0	0.00	0.00	0	0
37	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	51,245	51,245
38	Other transactions including adj.		227,496,702	194,294,618	33,202,084	0.00	0.00	0	0
39	TOTAL ACTUAL SALES		557,466,041	195,592,706	361,873,335	1.56	1.71	8,690,972	9,539,123
40	Difference in Amount		342,633,041	195,592,706	147,040,335	(1.44)	(1.67)	2,247,972	2,285,123
41	Difference in Percent		159.49	0.00	68.44	(48.00)	(49.41)	34.89	31.50

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 37

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: JANUARY 2015

(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: JANUARY 2015

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.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	0	0	0	0	0.00	0.00	0
3	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	11
4	Ascend Performance Materials	COG 1	13,053,000	0	0	0	2.65	2.65	346,153
5	International Paper	COG 1	197,000	0	0	0	2.80	2.80	5,522
6	TOTAL		13,250,000	0	0	0	2.65	2.65	351,687

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.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	0	0	0	0	0.00	0.00	0
3	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	11
4	Ascend Performance Materials	COG 1	13,053,000	0	0	0	2.65	2.65	346,153
5	International Paper	COG 1	197,000	0	0	0	2.80	2.80	5,522
6	TOTAL		13,250,000	0	0	0	2.65	2.65	351,687

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2015

	(1)	CURRENT MONTH (2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	PERIOD - TO - DATE (5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	PURCHASED FROM						
	ESTIMATED						
1	Southern Company Interchange	108,405,000	3.58	3,880,000	108,405,000	3.58	3,880,000
2	Economy Energy	4,613,000	3.69	170,000	4,613,000	3.69	170,000
3	Other Purchases	427,156,000	3.49	14,918,000	427,156,000	3.49	14,918,000
4	TOTAL ESTIMATED PURCHASES	540,174,000	3.51	18,968,000	540,174,000	3.51	18,968,000
	ACTUAL						
5	Southern Company Interchange	96,273,850	3.04	2,923,019	96,273,850	3.04	2,923,019
6	Non-Associated Companies	55,297,714	1.34	743,135	55,297,714	1.34	743,135
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	462,340,000	2.91	13,470,024	462,340,000	2.91	13,470,024
9	Other Wheeled Energy	51,023,000	0.00	N/A	51,023,000	0.00	N/A
10	Other Transactions	137,309,724	0.01	15,143	137,309,724	0.01	15,143
11	Less: Flow-Thru Energy	(17,641,555)	2.62	(462,425)	(17,641,555)	2.62	(462,425)
12	TOTAL ACTUAL PURCHASES	784,602,733	2.13	16,688,896	784,602,733	2.13	16,688,896
13	Difference in Amount	244,428,733	(1.38)	(2,279,104)	244,428,733	(1.38)	(2,279,104)
14	Difference in Percent	45.25	(39.32)	(12.02)	45.25	(39.32)	(12.02)

2015 CAPACITY CONTRACTS
GULF POWER COMPANY

	(A)	(B)		(C)		(D)		(E)		(F)		(G)		(H)		(I)
				JAN		FEB		MAR		APR		MAY		JUN		SUBTOTAL
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0.0	0											0
SUBTOTAL				0.0	$ -	0.0	$ -	0.0	$ -	0.0	$ -	0.0	$ -	0.0	$ -	$ -
B. CONFIDENTIAL CAPACITY CONTRACTS																
Power Purchase Agreements & Other																
1 Confidential Agreements	Other	Varies	Varies	885.0	7,387,528											7,387,528
SUBTOTAL					$ 7,387,528		$ -		$ -		$ -		$ -		$ -	$ 7,387,528
TOTAL					**$ 7,387,528**		**$ -**		**$ -**		**$ -**		**$ -**		**$ -**	**$ 7,387,528**

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2015 Final True-Up Filing
Exhibit CSB-1, Page 23 of 202

2015 CAPACITY CONTRACTS
GULF POWER COMPANY

		(J)	(K)		(L)		(M)		(N)		(O)		(P)		(Q)		(R)
					JUL		AUG		SEP		OCT		NOV		DEC		YTD
	A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW $		MW $		MW $		MW $		MW $		MW $		$
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice													0
	SUBTOTAL				0.0	$ -	0.0	$ -	0.0	$ -	0.0	$ -	0.0	$ -	0.0	$ -	$ -
	B. CONFIDENTIAL CAPACITY CONTRACTS																
	Power Purchase Agreements & Other																
1	Confidential Agreements	Other	Varies	Varies													7,387,528
	SUBTOTAL				$	-	$	-	$	-	$	-	$	-	$	-	$ 7,387,528
	TOTAL				**$**	**-**	**$**	**-**	**$**	**-**	**$**	**-**	**$**	**-**	**$**	**-**	**$ 7,387,528**

Docket No. 160001-EI
2015 Final True-Up Filing
Exhibit CSB-1, Page 24 of 202

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 150001-EI

MONTHLY FUEL FILING

February 2015

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
FEBRUARY 2015

		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)	25,860,562	26,737,937	(877,375)	(3.28)	740,335,000	692,880,000	47,455,000	6.85	3.4931	3.8590	(0.37)	(9.48)
2	Hedging Settlement Costs (A2)	4,645,635	0	4,645,635	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	626	0	626	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	30,506,823	26,737,937	3,768,886	14.10	740,335,000	692,880,000	47,455,000	6.85	4.1207	3.8590	0.26	6.78
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	14,221,106	15,687,000	(1,465,894)	(9.34)	747,889,904	451,484,000	296,405,904	65.65	1.9015	3.4745	(1.57)	(45.27)
9	Energy Cost of Schedule E Economy Purch. (A9)	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	737,356	0	737,356	100.00	21,714,000	0	21,714,000	100.00	3.3958	0.0000	3.40	0.00
12	TOTAL COST OF PURCHASED POWER	14,958,462	15,687,000	(728,538)	(4.64)	769,603,904	451,484,000	318,119,904	70.46	1.9437	3.4745	(1.53)	(44.06)
13	Total Available MWH (Line 5 + Line 12)	45,465,285	42,424,937	3,040,348	7.17	1,509,938,904	1,144,364,000	365,574,904	31.95				
14	Fuel Cost of Economy Sales (A6)	(606,153)	(357,000)	(249,153)	69.79	(24,924,152)	(11,596,000)	(13,328,152)	114.94	(2.4320)	(3.0786)	0.65	21.00
15	Gain on Economy Sales (A6)	(182,370)	(33,000)	(149,370)	452.64	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(10,886,041)	(9,845,000)	(1,041,041)	10.57	(589,640,996)	(327,974,000)	(261,666,996)	79.78	(1.8462)	(3.0018)	1.16	38.50
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(11,674,564)	(10,235,000)	(1,439,564)	14.07	(614,565,148)	(339,570,000)	(274,995,148)	80.98	(1.8996)	(3.0141)	1.11	36.98
18	Net Inadvertant Interchange	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	33,790,721	32,189,937	1,600,784	4.97	895,373,756	804,794,000	90,579,756	11.26	3.7739	3.9998	(0.23)	(5.65)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	69,970	75,476	(5,506)	(7.30)	1,854,038	1,887,000	(32,962)	(1.75)	3.7739	3.9998	(0.23)	(5.65)
22	T & D Losses *	1,603,854	1,437,928	165,926	11.54	42,498,593	35,950,000	6,548,593	18.22	3.7739	3.9998	(0.23)	(5.65)
23	TERRITORIAL KWH SALES	33,790,721	32,189,937	1,600,784	4.97	851,021,125	766,957,000	84,064,125	10.96	3.9706	4.1971	(0.23)	(5.40)
24	Wholesale KWH Sales	1,005,307	1,062,172	(56,865)	(5.35)	25,318,858	25,307,000	11,858	0.05	3.9706	4.1971	(0.23)	(5.40)
25	Jurisdictional KWH Sales	32,785,414	31,127,765	1,657,649	5.33	825,702,267	741,650,000	84,052,267	11.33	3.9706	4.1971	(0.23)	(5.40)
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	32,834,592	31,174,457	1,660,135	5.33	825,702,267	741,650,000	84,052,267	11.33	3.9766	4.2034	(0.23)	(5.40)
28	TRUE-UP	3,996,375	3,996,375	0	0.00	825,702,267	741,650,000	84,052,267	11.33	0.4840	0.5388	(0.05)	(10.17)
29	TOTAL JURISDICTIONAL FUEL COST	36,830,967	35,170,832	1,660,135	4.72	825,702,267	741,650,000	84,052,267	11.33	4.4606	4.7422	(0.28)	(5.94)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.4638	4.7456	(0.28)	(5.94)
32	GPIF Reward / (Penalty)	210,328	210,328	0	0.00	825,702,267	741,650,000	84,052,267	11.33	0.0255	0.0284	(0.00)	(10.21)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.4893	4.7740	(0.28)	(5.96)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.489	4.774		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: FEBRUARY 2015

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 25,860,562
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	626
4	Hedging Settlement Costs	Schedule A-2, Line A-5	4,645,635
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	14,221,106
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	737,356
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(11,674,564)
10	Total Fuel and Net Power Transactions		$ 33,790,721

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
FEBRUARY 2015
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)	50,664,408	53,270,840	(2,606,432)	(4.89)	1,446,275,000	1,321,661,000	124,614,000	9.43	3.5031	4.0306	(0.53)	(13.09)
2	Hedging Settlement Costs (A2)	8,650,350	0	8,650,350	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	536	0	536	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	59,315,294	53,270,840	6,044,454	11.35	1,446,275,000	1,321,661,000	124,614,000	9.43	4.1012	4.0306	0.07	1.75
6	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
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	30,910,003	34,655,000	(3,744,997)	(10.81)	1,540,284,738	991,658,000	548,626,738	55.32	2.0068	3.4947	(1.49)	(42.58)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	1,089,043	0	1,089,043	100.00	34,964,000	0	34,964,000	100.00	3.1148	0.0000	3.11	0.00
12	TOTAL COST OF PURCHASED POWER	31,999,046	34,655,000	(2,655,954)	(7.66)	1,575,248,738	991,658,000	583,590,738	58.85	2.0314	3.4947	(1.46)	(41.87)
13	Total Available MWH (Line 5 + Line 12)	91,314,340	87,925,840	3,388,500	3.85	3,021,523,738	2,313,319,000	708,204,738	30.61				
14	Fuel Cost of Economy Sales (A6)	(1,055,222)	(679,000)	(376,222)	55.41	(43,484,054)	(21,851,000)	(21,633,054)	99.00	(2.4267)	(3.1074)	0.68	21.91
15	Gain on Economy Sales (A6)	(233,615)	(68,000)	(165,615)	243.55	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(19,076,699)	(15,931,000)	(3,145,699)	19.75	(1,136,339,236)	(532,552,000)	(603,787,236)	113.38	(1.6788)	(2.9914)	1.31	43.88
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(20,365,536)	(16,678,000)	(3,687,536)	22.11	(1,179,823,290)	(554,403,000)	(625,420,290)	112.81	(1.7262)	(3.0083)	1.28	42.62
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	70,948,804	71,247,840	(299,036)	(0.42)	1,841,700,448	1,758,916,000	82,784,448	4.71	3.8524	4.0507	(0.20)	(4.90)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	145,418	153,493	(8,075)	(5.26)	3,774,742	3,789,300	(14,558)	(0.38)	3.8524	4.0507	(0.20)	(4.90)
22	T & D Losses *	3,522,256	3,478,000	44,256	1.27	91,430,168	85,861,700	5,568,468	6.49	3.8524	4.0507	(0.20)	(4.90)
23	TERRITORIAL KWH SALES	70,948,804	71,247,840	(299,036)	(0.42)	1,746,495,538	1,669,265,000	77,230,538	4.63	4.0624	4.2682	(0.21)	(4.82)
24	Wholesale KWH Sales	2,147,249	2,363,386	(216,137)	(9.15)	52,838,376	55,367,000	(2,528,624)	(4.57)	4.0638	4.2686	(0.20)	(4.80)
25	Jurisdictional KWH Sales	68,801,555	68,884,454	(82,899)	(0.12)	1,693,657,162	1,613,898,000	79,759,162	4.94	4.0623	4.2682	(0.21)	(4.82)
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	68,904,757	68,987,781	(83,024)	(0.12)	1,693,657,162	1,613,898,000	79,759,162	4.94	4.0684	4.2746	(0.21)	(4.82)
28	TRUE-UP	7,992,745	7,992,745	0	0.00	1,693,657,162	1,613,898,000	79,759,162	4.94	0.4719	0.4952	(0.02)	(4.71)
29	TOTAL JURISDICTIONAL FUEL COST	76,897,502	76,980,526	(83,024)	(0.11)	1,693,657,162	1,613,898,000	79,759,162	4.94	4.5403	4.7698	(0.23)	(4.81)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.5436	4.7732	(0.23)	(4.81)
32	GPIF Reward / (Penalty)	420,658	420,658	0	0.00	1,693,657,162	1,613,898,000	79,759,162	4.94	0.0248	0.0261	(0.00)	(4.98)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.5684	4.7993	(0.23)	(4.81)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.568	4.799		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

Docket No. 160001-EI
2015 Final True-Up Filing
Exhibit CSB-1, Page 28 of 202

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2015

		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	25,625,681.51	26,549,512	(923,830.49)	(3.48)	50,197,316.43	52,873,864	(2,676,547.57)	(5.06)
1a	Other Generation	234,880.03	188,425	46,455.03	24.65	467,092.03	396,976	70,116.03	17.66
2	Fuel Cost of Power Sold	(11,674,563.09)	(10,235,000)	(1,439,563.09)	(14.07)	(20,365,535.84)	(16,678,000)	(3,687,535.84)	(22.11)
3	Fuel Cost - Purchased Power	14,221,106.03	15,687,000	(1,465,893.97)	(9.34)	30,910,002.63	34,655,000	(3,744,997.37)	(10.81)
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	737,355.81	0	737,355.81	100.00	1,089,042.54	0	1,089,042.54	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	4,645,635.00	0	4,645,635.00	100.00	8,650,350.00	0	8,650,350.00	100.00
6	Total Fuel & Net Power Transactions	33,790,095.29	32,189,937	1,600,158.29	4.97	70,948,267.79	71,247,840	(299,572.21)	(0.42)
7	AdjustmentsTo Fuel Cost*	626.13	0	626.13	100.00	536.02	0	536.02	100.00
8	Adj. Total Fuel & Net Power Transactions	33,790,721.42	32,189,937	1,600,784.42	4.97	70,948,803.81	71,247,840	(299,036.19)	(0.42)
B.	*KWH Sales*								
1	Jurisdictional Sales	825,702,267	741,650,000	84,052,267	11.33	1,693,657,162	1,613,898,000	79,759,162	4.94
2	Non-Jurisdictional Sales	25,318,858	25,307,000	11,858	0.05	52,838,376	55,367,000	(2,528,624)	(4.57)
3	Total Territorial Sales	851,021,125	766,957,000	84,064,125	10.96	1,746,495,538	1,669,265,000	77,230,538	4.63
4	Juris. Sales as % of Total Terr. Sales	97.0249	96.7003	0.3246	0.34	96.9746	96.6832	0.2914	0.30

**(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: FEBRUARY 2015

		CURRENT MONTH				PERIOD - TO - DATE			
				$ DIFFERENCE				$ DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	35,306,605.99	32,128,878	3,177,727.98	9.89	72,023,215.06	69,915,367	2,107,848.03	3.01
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(3,996,375.00)	3,996,375	(7,992,750.00)	(200.00)	(7,992,745.00)	7,992,745	(15,985,490.00)	(200.00)
2b	Incentive Provision	(210,177.00)	(210,177)	0.00	0.00	(420,352.00)	(420,352)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	31,100,053.99	35,915,076	(4,815,022.01)	(13.41)	63,610,118.06	77,487,760	(13,877,641.94)	(17.91)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	33,790,721.42	32,189,937	1,600,784.42	4.97	70,948,804.41	71,247,840	(299,035.59)	(0.42)
5	Juris. Sales % of Total KWH Sales (Line B4)	97.0249	96.7003	0.3246	0.34	96.9746	96.6832	0.2914	0.30
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	32,834,591.79	31,174,457	1,660,134.79	5.33	68,904,756.78	68,987,781	(83,024.22)	(0.12)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(1,734,537.80)	4,740,619	(6,475,156.80)	136.59	(5,294,638.72)	8,499,979	(13,794,617.72)	162.29
8	Interest Provision for the Month	(3,026.32)	(3,778)	751.68	19.90	(6,317.57)	(7,768)	1,450.43	18.67
9	Beginning True-Up & Interest Provision	(39,438,763.59)	(48,197,495)	8,758,731.41	18.17	(39,871,741.42)	(47,956,495)	8,084,753.58	16.86
10	True-Up Collected / (Refunded)	3,996,375.00	(3,996,375)	7,992,750.00	(200.00)	7,992,745.00	(7,992,745)	15,985,490.00	(200.00)
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(37,179,952.71)	(47,457,029)	10,277,076.29	21.66	(37,179,952.71)	(47,457,029)	10,277,076.29	21.66
12	Adjustment	0.00	0	0.00	0.00	0.00	0	0.00	0.00
13	End of Period - Total Net True-Up	(37,179,952.71)	(47,457,029)	10,277,076.29	21.66	(37,179,952.71)	(47,457,029)	10,277,076.29	21.66

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2015

		CURRENT MONTH			
		$		*DIFFERENCE*	
		ACTUAL	**ESTIMATED**	**AMOUNT ($)**	**%**
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(39,438,763.59)	(48,197,495)	8,758,731.41	(18.17)
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	(37,176,926.39)	(47,453,251)	10,276,324.61	(21.66)
3	Total of Beginning & Ending True-Up Amts.	(76,615,689.98)	(95,650,746)	19,035,056.02	(19.90)
4	Average True-Up Amount	(38,307,844.99)	(47,825,373)	9,517,528.01	(19.90)
	Interest Rate				
5	1st Day of Reporting Business Month	0.10	0.10	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.09	0.09	0.0000	
7	Total (D5+D6)	0.19	0.19	0.0000	
8	Annual Average Interest Rate	0.10	0.10	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0079	0.0079	0.0000	
10	Interest Provision (D4*D9)	(3,026.32)	(3,778)	751.68	(19.90)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0015		

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2015

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	178,774	106,902	71,872	67.23	400,204	243,651	156,553	64.25
2	COAL	16,811,528	14,633,280	2,178,248	14.89	31,163,155	29,592,522	1,570,633	5.31
3	GAS	8,774,428	11,713,055	(2,938,627)	(25.09)	18,587,639	22,859,116	(4,271,477)	(18.69)
4	GAS (B.L.)	-	227,536	(227,536)	(100.00)	267,158	455,072	(187,914)	(41.29)
5	LANDFILL GAS	61,160	57,164	3,996	6.99	123,691	120,479	3,212	2.67
6	OIL - C.T.	34,671	0	34,671	100.00	122,560	0	122,560	100.00
7	TOTAL ($)	25,860,562	26,737,937	(877,375)	(3.28)	50,664,408	53,270,840	(2,606,432)	(4.89)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	399,658	375,344	24,314	6.48	735,448	715,012	20,436	2.86
10	GAS	338,551	315,640	22,911	7.26	706,225	602,653	103,572	17.19
11	LANDFILL GAS	2,043	1,896	147	7.75	4,127	3,996	131	3.28
12	OIL - C.T.	83	0	83	100.00	475	0	475	100.00
13	TOTAL (MWH)	740,335	692,880	47,455	6.85	1,446,275	1,321,661	124,614	9.43
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	1,862	856	1,006	117.52	4,291	1,947	2,344	120.39
15	COAL (TONS)	193,018	175,374	17,644	10.06	353,665	334,431	19,234	5.75
16	GAS (MCF) (1)	2,364,176	2,132,631	231,545	10.86	4,890,427	4,069,617	820,810	20.17
17	OIL - C.T. (BBL)	314	0	314	100.00	1,109	0	1,109	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	4,368,368	4,002,674	365,694	9.14	8,085,106	7,772,967	312,139	4.02
19	GAS - Generation (1)	2,424,925	2,132,631	292,294	13.71	4,957,218	4,069,617	887,601	21.81
20	OIL - C.T.	1,832	0	1,832	100.00	6,466	0	6,466	100.00
21	TOTAL (MMBTU)	6,795,125	6,135,305	659,820	10.75	13,048,790	11,842,584	1,206,206	10.19
	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	53.98	54.18	(0.20)	(0.37)	50.86	54.10	(3.24)	(5.99)
24	GAS	45.73	45.55	0.18	0.40	48.83	45.60	3.23	7.08
25	LANDFILL GAS	0.28	0.27	0.01	3.70	0.29	0.30	(0.01)	(3.33)
26	OIL - C.T.	0.01	0.00	0.01	100.00	0.02	0.00	0.02	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)	95.99	124.89	(28.90)	(23.14)	93.27	125.14	(31.87)	(25.47)
29	COAL ($/TON)	87.10	83.44	3.66	4.39	88.11	88.49	(0.38)	(0.43)
30	GAS ($/MCF) (1)	3.61	5.51	(1.90)	(34.48)	3.76	5.63	(1.87)	(33.21)
31	OIL - C.T. ($/BBL)	110.42	0.00	110.42	100.00	110.51	0.00	110.51	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	3.89	3.74	0.15	4.01	3.94	3.90	0.04	1.03
33	GAS - Generation (1)	3.52	5.40	(1.88)	(34.81)	3.66	5.52	(1.86)	(33.70)
34	OIL - C.T.	18.93	0.00	18.93	100.00	18.95	0.00	18.95	100.00
35	TOTAL ($/MMBTU)	3.76	4.32	(0.56)	(12.96)	3.84	4.45	(0.61)	(13.71)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	10,930	10,664	266	2.49	10,993	10,871	122	1.12
37	GAS - Generation (1)	7,293	6,869	424	6.17	7,146	6,877	269	3.91
38	OIL - C.T.	22,068	0	22,068	100.00	13,613	0	13,613	100.00
39	TOTAL (BTU/KWH)	9,280	8,946	334	3.73	9,128	9,062	66	0.73
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	4.25	3.99	0.26	6.52	4.33	4.24	0.09	2.12
41	GAS	2.59	3.71	(1.12)	(30.19)	2.63	3.79	(1.16)	(30.61)
42	LANDFILL GAS	2.99	3.01	(0.02)	(0.66)	3.00	3.01	(0.01)	(0.33)
43	OIL - C.T.	41.77	0.00	41.77	100.00	25.80	0.00	25.80	100.00
44	TOTAL (¢/KWH)	3.49	3.86	(0.37)	(9.59)	3.50	4.03	(0.53)	(13.15)

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: FEBRUARY 2015

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2015	(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	35,987	71.4	100.0	71.4	10,520	Coal	16,552	11,436	378,579	1,494,339	4.15	90.28
2				0					Gas-G	0	1,020	0	0	0.00	0.00
3									Gas-S	0	1,020	0	0		0.00
4									Oil-S	58	137,660	334	7,378		127.21
5	Crist 5		75	(911)	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
6				-					Gas-G	0	1,020	0	0	0.00	0.00
7									Gas-S	0	1,020	0	0		0.00
8									Oil-S	0	137,660	0	0		0.00
9	Crist 6		299	69,690	34.7	90.0	57.8	9,507	Coal	29,038	11,408	662,521	2,621,541	3.76	90.28
10				0					Gas-G	99,423	1,020	101,411	395,332	0.00	0.00
11									Gas-S	0	1,020	0	0		0.00
12									Oil-S	73	137,660	419	9,270		126.99
13	Crist 7		475	159,750	50.0	89.9	53.5	10,416	Coal	72,357	11,498	1,663,911	6,532,421	4.09	90.28
14				0					Gas-G	20,494	1,020	20,904	81,489	0.00	3.98
15									Gas-S	0	1,020	0	0		0.00
16									Oil-S	138	137,660	800	17,690		128.19
17	Scholz 1		46	(307)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	0	0	0		0.00
19	Scholz 2		46	18,600	60.2	79.0	63.3	12,379	Coal	10,235	11,248	230,246	840,606	4.52	82.13
20									Oil-S	44	0	255	5,797		131.75
21	Smith 1		162	56,569	52.0	100.0	52.0	10,931	Coal	27,756	11,139	618,340	2,381,021	4.21	85.79
22									Oil-S	41	138,582	239	3,364		82.05
23	Smith 2		195	31,468	24.0	100.0	40.5	11,386	Coal	16,303	10,989	358,310	1,398,563	4.44	85.79
24									Oil-S	357	138,582	2,085	29,407		82.37
25	Smith 3		584	321,465	81.9	99.0	91.9	7,163	Gas-G	2,244,259	1,026	2,302,610	8,062,727	2.51	3.59
26	Smith A	(2)	40	83	0.3	99.0	83.0	22,072	Oil	314	138,971	1,832	34,671	41.77	110.42
27	Other Generation			6,049									234,880	3.88	0.00
28	Perdido			2,043					Landfill Gas				61,160	2.99	0.00
29	Daniel 1	(1)	255	(516)	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
30									Oil-S	0	138,959	0	0		0.00
31	Daniel 2	(1)	255	40,365	23.6	98.1	41.1	11,040	Coal	20,778	10,723	445,614	1,547,022	3.83	74.45
32									Oil-S	1,151	138,959	6,715	105,868		91.98
33	Total		2,507	740,335	43.9	82.9	53.7	9,280				6,795,125	25,864,546	3.49	

Notes & Adjust.: (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

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.	(3,984)	
	Recoverable Fuel	25,860,562	3.49

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SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2015

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES :*								
2	UNITS (BBL)	1,265	856	409	47.78	3,514	1,947	1,567	80.48
3	UNIT COST ($/BBL)	80.55	122.82	(42.27)	(34.42)	73.00	122.76	(49.76)	(40.53)
4	AMOUNT ($)	101,896	105,132	(3,236)	(3.08)	256,539	239,022	17,517	7.33
5	*BURNED :*								
6	UNITS (BBL)	1,909	856	1,053	123.01	4,374	1,947	2,427	124.65
7	UNIT COST ($/BBL)	96.09	124.89	(28.80)	(23.06)	93.32	125.14	(31.82)	(25.43)
8	AMOUNT ($)	183,431	106,902	76,529	71.59	408,186	243,651	164,535	67.53
9	*ENDING INVENTORY :*								
10	UNITS (BBL)	6,136	7,166	(1,030)	(14.37)	6,136	7,166	(1,030)	(14.37)
11	UNIT COST ($/BBL)	108.43	126.16	(17.73)	(14.05)	108.43	126.16	(17.73)	(14.05)
12	AMOUNT ($)	665,336	904,048	(238,712)	(26.40)	665,336	904,048	(238,712)	(26.40)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES :*								
15	UNITS (TONS)	147,058	175,911	(28,853)	(16.40)	344,949	301,542	43,407	14.40
16	UNIT COST ($/TON)	86.53	79.82	6.71	8.41	86.36	79.52	6.84	8.60
17	AMOUNT ($)	12,724,662	14,041,663	(1,317,001)	(9.38)	29,789,445	23,979,210	5,810,235	24.23
18	*BURNED :*								
19	UNITS (TONS)	193,018	175,374	17,644	10.06	353,665	334,431	19,234	5.75
20	UNIT COST ($/TON)	87.12	83.44	3.68	4.41	88.14	88.49	(0.35)	(0.40)
21	AMOUNT ($)	16,815,512	14,633,280	2,182,232	14.91	31,171,200	29,592,522	1,578,678	5.33
22	*ENDING INVENTORY :*								
23	UNITS (TONS)	547,746	471,262	76,484	16.23	547,746	471,262	76,484	16.23
24	UNIT COST ($/TON)	80.41	77.18	3.23	4.19	80.41	77.18	3.23	4.19
25	AMOUNT ($)	44,043,618	36,370,404	7,673,214	21.10	44,043,618	36,370,404	7,673,214	21.10
26	DAYS SUPPLY	27	23	4	17.39				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES :*								
28	UNITS (MMBTU)	2,098,533	2,152,631	(54,098)	(2.51)	4,604,326	4,109,617	494,709	12.04
29	UNIT COST ($/MMBTU)	3.40	5.46	(2.06)	(37.73)	3.53	5.58	(2.05)	(36.74)
30	AMOUNT ($)	7,131,333	11,752,166	(4,620,833)	(39.32)	16,252,203	22,917,212	(6,665,009)	(29.08)
31	*BURNED :*								
32	UNITS (MMBTU)	2,424,925	2,152,631	272,294	12.65	5,018,828	4,109,617	909,211	22.12
33	UNIT COST ($/MMBTU)	3.52	5.46	(1.94)	(35.53)	3.66	5.58	(1.92)	(34.41)
34	AMOUNT ($)	8,538,798	11,752,166	(3,213,368)	(27.34)	18,386,205	22,917,212	(4,531,007)	(19.77)
35	*ENDING INVENTORY :*								
36	UNITS (MMBTU)	626,840	0	626,840	100.00	626,840	0	626,840	100.00
37	UNIT COST ($/MMBTU)	3.50	0.00	3.50	100.00	3.50	0.00	3.50	100.00
38	AMOUNT ($)	2,194,714	0	2,194,714	100.00	2,194,714	0	2,194,714	100.00
	OTHER - C.T. OIL								
39	*PURCHASES :*								
40	UNITS (BBL) *	0	0	0	0.00	894	0	894	100.00
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	68.86	0.00	69.00	100.00
42	AMOUNT ($)	0	0	0	0.00	61,561	0	61,561	100.00
43	*BURNED :*								
44	UNITS (BBL)	314	0	314	100.00	1,109	0	1,109	100.00
45	UNIT COST ($/BBL)	110.42	0.00	110.42	100.00	110.51	0.00	110.51	100.00
46	AMOUNT ($)	34,671	0	34,671	100.00	122,559	0	122,559	100.00
47	*ENDING INVENTORY :*								
48	UNITS (BBL)	6,843	7,143	(300)	(4.20)	6,843	7,143	(300)	(4.20)
49	UNIT COST ($/BBL)	110.48	117.59	(7.11)	(6.05)	110.48	117.59	(7.11)	(6.05)
50	AMOUNT ($)	756,028	839,922	(83,894)	(9.99)	756,028	839,922	(83,894)	(9.99)
51	DAYS SUPPLY	3	3	0	0.00				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2015

			CURRENT MONTH						
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
				KWH		(a)	(b)	(5) x (6)(a)	(5) x (6)(b)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	¢ / KWH FUEL COST	¢ / KWH TOTAL COST	TOTAL $ FOR FUEL ADJ.	TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		327,974,000	0	327,974,000	3.00	3.38	9,845,000	11,077,000
2	Various	Economy Sales	11,596,000	0	11,596,000	3.08	3.33	357,000	386,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	33,000	33,000
4	TOTAL ESTIMATED SALES		339,570,000	0	339,570,000	3.01	3.39	10,235,000	11,496,000
	ACTUAL								
5	Southern Company Interchange		349,962,337	0	349,962,337	3.27	3.57	11,445,498	12,476,266
6	A.E.C.	External	8,163,144	0	8,163,144	2.38	2.96	194,263	241,232
7	AECI	External	17,443	0	17,443	3.03	4.20	529	733
8	AEP	External	0	0	0	0.00	0.00	0	0
9	BAM	External	5,903	0	5,903	2.00	3.27	118	193
10	CALPINE	External	0	0	0	0.00	0.00	0	0
11	CARGILE	External	201,480	0	201,480	2.35	3.46	4,738	6,978
12	DUKE PWR	External	1,312,808	0	1,312,808	2.36	3.81	30,984	49,977
13	EAGLE EN	External	662,747	0	662,747	3.50	5.72	23,225	37,883
14	ENDURE	External	35,150	0	35,150	2.46	4.24	864	1,492
15	EXELON	External	957,885	0	957,885	2.80	3.70	26,866	35,483
16	FPC	External	0	0	0	0.00	0.00	27	0
17	FPL	External	198,970	0	198,970	2.05	3.60	4,080	7,163
18	JPMVEC	External	67,117	0	67,117	2.42	3.95	1,622	2,650
19	MISO	External	787,760	0	787,760	1.99	2.88	15,668	22,682
20	MORGAN	External	1,211,565	0	1,211,565	2.09	2.96	25,272	35,920
21	NCEMC	External	643,090	0	643,090	2.38	3.44	15,278	22,101
22	NCMPA1	External	1,658	0	1,658	1.61	2.80	27	46
23	NRG	External	0	0	0	0.00	0.00	0	0
24	OPC	External	160,830	0	160,830	2.71	4.06	4,365	6,530
25	ORLANDO	External	0	0	0	0.00	0.00	0	0
26	PJM	External	2,212,163	0	2,212,163	2.33	4.54	51,511	100,435
27	SCE&G	External	1,130,018	0	1,130,018	3.90	4.69	44,043	53,015
28	SEC	External	4,974	0	4,974	2.27	5.10	113	254
29	SEPA	External	1,049,390	0	1,049,390	2.12	3.51	22,264	36,788
30	SPP	External	0	0	0	0.00	0.00	0	0
31	TAL	External	0	0	0	0.00	0.00	0	0
32	TEA	External	2,987,918	0	2,987,918	2.31	3.60	69,063	107,441
33	TECO	External	104,522	0	104,522	1.99	3.11	2,075	3,249
34	TENASKA	External	0	0	0	0.00	0.00	0	0
35	TVA	External	2,655,193	0	2,655,193	2.29	3.90	60,850	103,488
36	WRI	External	352,424	0	352,424	2.36	3.23	8,309	11,387
37	Less: Flow-Thru Energy		(23,794,134)	0	(23,794,134)	2.35	2.35	(559,457)	(559,457)
38	SEPA		1,038,664	1,038,664	0	0.00	0.00	0	0
39	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	182,370	182,370
40	Other transactions including adj.		262,434,129	167,778,604	94,655,525	0.00	0.00	0	0
41	TOTAL ACTUAL SALES		614,565,148	168,817,268	445,747,880	1.90	2.08	11,674,564	12,803,928
42	Difference in Amount		274,995,148	168,817,268	106,177,880	(1.11)	(1.31)	1,439,564	1,307,928
43	Difference in Percent		80.98	0.00	31.27	(36.88)	(38.64)	14.07	11.38

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 39

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2015

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		532,552,000	0	532,552,000	2.99	3.37	15,931,000	17,942,000
2	Various	Economy Sales	21,851,000	0	21,851,000	3.11	3.39	679,000	740,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	68,000	68,000
4	TOTAL ESTIMATED SALES		554,403,000	0	554,403,000	3.01	3.38	16,678,000	18,750,000
	ACTUAL								
5	Southern Company Interchange		677,715,241	0	677,715,241	2.96	3.23	20,057,566	21,868,235
6	A.E.C.	External	16,892,464	0	16,892,464	2.42	2.96	409,368	500,005
7	AECI	External	401,439	0	401,439	2.37	2.99	9,528	11,994
8	AEP	External	0	0	0	0.00	0.00	0	0
9	BAM	External	5,903	0	5,903	2.00	3.27	118	193
10	CALPINE	External	0	0	0	0.00	0.00	0	0
11	CARGILE	External	351,701	0	351,701	2.54	3.24	8,919	11,412
12	DUKE PWR	External	1,934,703	0	1,934,703	2.33	3.70	45,046	71,655
13	EAGLE EN	External	1,047,735	0	1,047,735	2.98	4.64	31,230	48,574
14	ENDURE	External	41,782	0	41,782	2.40	4.13	1,003	1,724
15	EXELON	External	1,092,252	0	1,092,252	2.74	3.62	29,894	39,576
16	FPC	External	85,820	0	85,820	2.02	2.83	1,733	2,425
17	FPL	External	198,970	0	198,970	2.05	3.60	4,080	7,163
18	JPMVEC	External	97,295	0	97,295	2.32	3.63	2,257	3,534
19	MISO	External	1,472,655	0	1,472,655	1.98	2.82	29,090	41,588
20	MORGAN	External	1,736,093	0	1,736,093	2.42	2.93	42,093	50,944
21	NCEMC	External	837,606	0	837,606	2.56	3.40	21,455	28,489
22	NCMPA1	External	1,658	0	1,658	1.61	2.80	27	46
23	NRG	External	0	0	0	0.00	0.00	0	0
24	OPC	External	453,505	0	453,505	2.61	3.83	11,844	17,376
25	ORLANDO	External	9,948	0	9,948	2.81	4.20	280	418
26	PJM	External	3,869,743	0	3,869,743	2.39	4.05	92,611	156,730
27	SCE&G	External	2,047,370	0	2,047,370	3.44	4.13	70,442	84,620
28	SEC	External	41,450	0	41,450	2.89	3.68	1,198	1,524
29	SEPA	External	2,274,334	0	2,274,334	2.11	3.26	47,995	74,030
30	SPP	External	0	0	0	0.00	0.00	0	0
31	TAL	External	0	0	0	0.00	0.00	0	0
32	TEA	External	4,956,870	0	4,956,870	2.25	3.39	111,353	168,192
33	TECO	External	134,369	0	134,369	2.06	3.18	2,765	4,274
34	TENASKA	External	0	0	0	0.00	0.00	0	0
35	TVA	External	2,774,573	0	2,774,573	2.31	3.89	64,108	107,835
36	WRI	External	723,816	0	723,816	2.32	2.95	16,783	21,362
37	Less: Flow-Thru Energy		(41,435,689)	0	(41,435,689)	2.37	2.37	(980,867)	(980,867)
38	SEPA		2,336,752	2,336,752	0	0.00	0.00	0	0
39	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	233,616	233,615
40	Other transactions including adj.		497,722,932	362,073,222	135,649,710	0.00	0.00	0	0
41	TOTAL ACTUAL SALES		1,179,823,290	364,409,974	815,413,316	1.73	1.89	20,365,536	22,343,051
42	Difference in Amount		625,420,290	364,409,974	261,010,316	(1.28)	(1.49)	3,687,536	3,593,051
43	Difference in Percent		112.81	0.00	47.08	(42.52)	(44.08)	22.11	19.16

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 39

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: FEBRUARY 2015

(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: FEBRUARY 2015

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.
ESTIMATED								
1		0	0	0	0	0.00	0.00	0
ACTUAL								
2 Bay County/Engen, LLC	Contract	3,564,000	0	0	0	3.52	3.52	125,396
3 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
4 Ascend Performance Materials	COG 1	17,929,000	0	0	0	3.37	3.37	604,952
5 International Paper	COG 1	221,000	0	0	0	3.17	3.17	7,008
6 TOTAL		21,714,000	0	0	0	3.40	3.40	737,356

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.
ESTIMATED								
1		0	0	0	0	0.00	0.00	0
ACTUAL								
2 Bay County/Engen, LLC	Contract	3,564,000	0	0	0	3.52	3.52	125,396
3 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	11
4 Ascend Performance Materials	COG 1	30,982,000	0	0	0	3.07	3.07	951,105
5 International Paper	COG 1	418,000	0	0	0	3.00	3.00	12,530
6 TOTAL		34,964,000	0	0	0	3.11	3.11	1,089,043

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2015

	(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	83,945,000	3.22	2,703,000	192,350,000	3.42	6,583,000
2	Economy Energy	2,298,000	3.70	85,000	6,911,000	3.69	255,000
3	Other Purchases	365,241,000	3.53	12,899,000	792,397,000	3.51	27,817,000
4	TOTAL ESTIMATED PURCHASES	451,484,000	3.47	15,687,000	991,658,000	3.49	34,655,000
	ACTUAL						
5	Southern Company Interchange	114,241,002	2.93	3,343,684	218,306,953	2.87	6,266,704
6	Non-Associated Companies	50,459,202	1.37	689,958	105,756,916	1.36	1,433,093
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	386,459,000	2.79	10,782,811	848,799,000	2.86	24,252,835
9	Other Wheeled Energy	110,445,000	0.00	N/A	161,468,000	0.00	N/A
10	Other Transactions	110,079,834	0.03	30,268	247,389,558	0.02	45,411
11	Less: Flow-Thru Energy	(23,794,134)	2.63	(625,615)	(41,435,689)	2.63	(1,088,040)
12	TOTAL ACTUAL PURCHASES	747,889,904	1.90	14,221,106	1,540,284,738	2.01	30,910,003
13	Difference in Amount	296,405,904	(1.57)	(1,465,894)	548,626,738	(1.48)	(3,744,997)
14	Difference in Percent	65.65	(45.24)	(9.34)	55.32	(42.41)	(10.81)

2015 CAPACITY CONTRACTS
GULF POWER COMPANY

	(A)	(B)		(C)		(D)		(E)		(F)		(G)		(H)		(I)
				JAN		FEB		MAR		APR		MAY		JUN		SUBTOTAL
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0.0	0	0.0	0									0
SUBTOTAL				0.0	$ -	0.0	$ -	0.0	$ -	0.0	$ -	0.0	$ -	0.0	$ -	$ -
B. CONFIDENTIAL CAPACITY CONTRACTS																
Power Purchase Agreements & Other																
1 Confidential Agreements	Other	Varies	Varies	885.0	7,387,528	885.0	7,392,119									14,779,647
SUBTOTAL					$ 7,387,528		$ 7,392,119		$ -		$ -		$ -		$ -	$ 14,779,647
TOTAL					**$ 7,387,528**		**$ 7,392,119**		**$ -**		**$ -**		**$ -**		**$ -**	**$ 14,779,647**

2015 CAPACITY CONTRACTS
GULF POWER COMPANY

	(J)	(K)		(L)		(M)		(N)		(O)		(P)		(Q)		(R)
				JUL		AUG		SEP		OCT		NOV		DEC		YTD
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice													0
SUBTOTAL				0.0	$ -	0.0	$ -	0.0	$ -	0.0	$ -	0.0	$ -	0.0	$ -	$ -
B. CONFIDENTIAL CAPACITY CONTRACTS																
Power Purchase Agreements & Other																
1 Confidential Agreements	Other	Varies	Varies													14,779,647
SUBTOTAL					$ -		$ -		$ -		$ -		$ -		$ -	$ 14,779,647
TOTAL					**$ -**		**$ -**		**$ -**		**$ -**		**$ -**		**$ -**	**$ 14,779,647**

Docket No. 160001-EI
2015 Final True-Up Filing
Exhibit CSB-1, Page 41 of 202

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 150001-EI

MONTHLY FUEL FILING

MARCH 2015

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
MARCH 2015

		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)	19,972,239	26,271,208	(6,298,969)	(23.98)	585,435,000	684,235,000	(98,800,000)	(14.44)	3.4115	3.8395	(0.43)	(11.15)
2	Hedging Settlement Costs (A2)	2,024,810	0	2,024,810	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	(125,410)	0	(125,410)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	21,871,639	26,271,208	(4,399,569)	(16.75)	585,435,000	684,235,000	(98,800,000)	(14.44)	3.7360	3.8395	(0.10)	(2.70)
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	6,206,307.02	6,622,000	(415,693)	(6.28)	449,917,571	164,878,000	285,039,571	172.88	1.3794	4.0163	(2.64)	(65.65)
9	Energy Cost of Schedule E Economy Purch. (A9)	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	506,349	0	506,349	100.00	19,492,000	0	19,492,000	100.00	2.5977	0.0000	2.60	0.00
12	TOTAL COST OF PURCHASED POWER	6,712,656	6,622,000	90,656	1.37	469,409,571	164,878,000	304,531,571	184.70	1.4300	4.0163	(2.59)	(64.40)
13	Total Available MWH (Line 5 + Line 12)	28,584,295	32,893,208	(4,308,913)	(13.10)	1,054,844,571	849,113,000	205,731,571	24.23				
14	Fuel Cost of Economy Sales (A6)	(387,599)	(268,000)	(119,599)	44.63	(18,493,339)	(8,955,000)	(9,538,339)	106.51	(2.0959)	(2.9927)	0.90	29.97
15	Gain on Economy Sales (A6)	(118,976)	(21,000)	(97,976)	466.55	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(39,550)	(433,000)	393,450	(90.87)	(207,239,636)	(14,838,000)	(192,401,636)	1,296.68	(0.0191)	(2.9182)	2.90	99.35
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(546,125)	(722,000)	175,875	(24.36)	(225,732,975)	(23,793,000)	(201,939,975)	848.74	(0.2419)	(3.0345)	2.79	92.03
18	Net Inadvertant Interchange	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	28,038,170	32,171,208	(4,133,038)	(12.85)	829,111,596	825,320,000	3,791,596	0.46	3.3817	3.8980	(0.52)	(13.25)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	59,877	68,761	(8,884)	(12.92)	1,770,605	1,764,000	6,605	0.37	3.3817	3.8980	(0.52)	(13.25)
22	T & D Losses *	1,445,595	1,470,598	(25,003)	(1.70)	42,747,571	37,727,000	5,020,571	13.31	3.3817	3.8980	(0.52)	(13.25)
23	TERRITORIAL KWH SALES	28,038,170	32,171,208	(4,133,038)	(12.85)	784,593,420	785,829,000	(1,235,580)	(0.16)	3.5736	4.0939	(0.52)	(12.71)
24	Wholesale KWH Sales	777,527	1,021,340	(243,813)	(23.87)	21,757,928	24,948,000	(3,190,072)	(12.79)	3.5735	4.0939	(0.52)	(12.71)
25	Jurisdictional KWH Sales	27,260,643	31,149,868	(3,889,225)	(12.49)	762,835,492	760,881,000	1,954,492	0.26	3.5736	4.0939	(0.52)	(12.71)
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	27,301,534	31,196,593	(3,895,059)	(12.49)	762,835,492	760,881,000	1,954,492	0.26	3.5790	4.1001	(0.52)	(12.71)
28	TRUE-UP	3,996,375	3,996,375	0	0.00	762,835,492	760,881,000	1,954,492	0.26	0.5239	0.5252	(0.00)	(0.25)
29	TOTAL JURISDICTIONAL FUEL COST	31,297,909	35,192,968	(3,895,059)	(11.07)	762,835,492	760,881,000	1,954,492	0.26	4.1029	4.6253	(0.52)	(11.29)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.1059	4.6286	(0.52)	(11.29)
32	GPIF Reward / (Penalty)	210,328	210,328	0	0.00	762,835,492	760,881,000	1,954,492	0.26	0.0276	0.0276	0.00	0.00
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.1335	4.6562	(0.52)	(11.23)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.134	4.656		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: MARCH 2015

LINE	DESCRIPTION	REFERENCE		AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$	19,972,239
2	Fuel Related Transactions			0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7		(125,410)
4	Hedging Settlement Costs	Schedule A-2, Line A-5		2,024,810
5	Fuel Cost of Purchased Power	Schedule A-7		0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12		6,206,307
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9		0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7		506,349
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line		(546,126)
10	Total Fuel and Net Power Transactions		$	28,038,169

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
MARCH 2015
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)	70,636,648	79,542,048	(8,905,400)	(11.20)	2,031,710,000	2,005,896,000	25,814,000	1.29	3.4767	3.9654	(0.49)	(12.32)
2	Hedging Settlement Costs (A2)	10,675,160	0	10,675,160	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	(124,875)	0	(124,875)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	81,186,933	79,542,048	1,644,885	2.07	2,031,710,000	2,005,896,000	25,814,000	1.29	3.9960	3.9654	0.03	0.77
6	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
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	37,116,310	41,277,000	(4,160,690)	(10.08)	1,990,202,309	1,156,536,000	833,666,309	72.08	1.8650	3.5690	(1.70)	(47.74)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	1,595,392	0	1,595,392	100.00	54,456,000	0	54,456,000	100.00	2.9297	0.0000	2.93	0.00
12	TOTAL COST OF PURCHASED POWER	38,711,702	41,277,000	(2,565,298)	(6.21)	2,044,658,309	1,156,536,000	888,122,309	76.79	1.8933	3.5690	(1.68)	(46.95)
13	Total Available MWH (Line 5 + Line 12)	119,898,635	120,819,048	(920,413)	(0.76)	4,076,368,309	3,162,432,000	913,936,309	28.90				
14	Fuel Cost of Economy Sales (A6)	(1,442,821)	(947,000)	(495,821)	52.36	(61,977,393)	(30,806,000)	(31,171,393)	101.19	(2.3280)	(3.0741)	0.75	24.27
15	Gain on Economy Sales (A6)	(352,591)	(89,000)	(263,591)	296.17	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(19,116,249)	(16,364,000)	(2,752,249)	16.82	(1,343,578,872)	(547,390,000)	(796,188,872)	145.45	(1.4228)	(2.9895)	1.57	52.41
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(20,911,661)	(17,400,000)	(3,511,661)	20.18	(1,405,556,265)	(578,196,000)	(827,360,265)	143.09	(1.4878)	(3.0094)	1.52	50.56
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	98,986,974	103,419,048	(4,432,074)	(4.29)	2,670,812,044	2,584,236,000	86,576,044	3.35	3.7063	4.0019	(0.30)	(7.39)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	205,527	222,238	(16,711)	(7.52)	5,545,347	5,553,300	(7,953)	(0.14)	3.7063	4.0019	(0.30)	(7.39)
22	T & D Losses *	4,973,030	4,945,896	27,134	0.55	134,177,739	123,588,700	10,589,039	8.57	3.7063	4.0019	(0.30)	(7.39)
23	TERRITORIAL KWH SALES	98,986,974	103,419,048	(4,432,074)	(4.29)	2,531,088,958	2,455,094,000	75,994,958	3.10	3.9108	4.2124	(0.30)	(7.16)
24	Wholesale KWH Sales	2,924,776	3,384,726	(459,950)	(13.59)	74,596,304	80,315,000	(5,718,696)	(7.12)	3.9208	4.2143	(0.29)	(6.96)
25	Jurisdictional KWH Sales	96,062,198	100,034,322	(3,972,124)	(3.97)	2,456,492,654	2,374,779,000	81,713,654	3.44	3.9105	4.2124	(0.30)	(7.17)
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	96,206,291	100,184,374	(3,978,083)	(3.97)	2,456,492,654	2,374,779,000	81,713,654	3.44	3.9164	4.2187	(0.30)	(7.17)
28	TRUE-UP	11,989,120	11,989,120	0	0.00	2,456,492,654	2,374,779,000	81,713,654	3.44	0.4881	0.5049	(0.02)	(3.33)
29	TOTAL JURISDICTIONAL FUEL COST	108,195,411	112,173,494	(3,978,083)	(3.55)	2,456,492,654	2,374,779,000	81,713,654	3.44	4.4045	4.7236	(0.32)	(6.76)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.4077	4.7270	(0.32)	(6.75)
32	GPIF Reward / (Penalty)	630,986	630,986	0	0.00	2,456,492,654	2,374,779,000	81,713,654	3.44	0.0257	0.0266	(0.00)	(3.38)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.4334	4.7536	(0.32)	(6.74)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.433	4.754		

* 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: MARCH 2015

		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	19,756,079.15	26,062,657	(6,306,577.85)	(24.20)	69,953,395.58	78,936,521	(8,983,125.42)	(11.38)
1a	Other Generation	216,160.28	208,551	7,609.28	3.65	683,252.31	605,527	77,725.31	12.84
2	Fuel Cost of Power Sold	(546,125.50)	(722,000)	175,874.50	24.36	(20,911,661.34)	(17,400,000)	(3,511,661.34)	(20.18)
3	Fuel Cost - Purchased Power	6,206,306.71	6,622,000	(415,693.29)	(6.28)	37,116,309.34	41,277,000	(4,160,690.66)	(10.08)
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	506,349.47	0	506,349.47	100.00	1,595,392.01	0	1,595,392.01	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	2,024,810.00	0	2,024,810.00	100.00	10,675,160.00	0	10,675,160.00	100.00
6	Total Fuel & Net Power Transactions	28,163,580.11	32,171,208	(4,007,627.89)	(12.46)	99,111,847.90	103,419,048	(4,307,200.10)	(4.16)
7	AdjustmentsTo Fuel Cost*	(125,410.22)	0	(125,410.22)	100.00	(124,874.20)	0	(124,874.20)	100.00
8	Adj. Total Fuel & Net Power Transactions	28,038,169.89	32,171,208	(4,133,038.11)	(12.85)	98,986,973.70	103,419,048	(4,432,074.30)	(4.29)
B.	*KWH Sales*								
1	Jurisdictional Sales	762,835,492	760,881,000	1,954,492	0.26	2,456,492,654	2,374,779,000	81,713,654	3.44
2	Non-Jurisdictional Sales	21,757,928	24,948,000	(3,190,072)	(12.79)	74,596,304	80,315,000	(5,718,696)	(7.12)
3	Total Territorial Sales	784,593,420	785,829,000	(1,235,580)	(0.16)	2,531,088,958	2,455,094,000	75,994,958	3.10
4	Juris. Sales as % of Total Terr. Sales	97.2269	96.8253	0.4016	0.41	97.0528	96.7286	0.3242	0.34

**(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: MARCH 2015

C. *True-up Calculation*	CURRENT MONTH $ ACTUAL	CURRENT MONTH $ ESTIMATED	CURRENT MONTH $ DIFFERENCE AMOUNT ($)	CURRENT MONTH DIFFERENCE %	PERIOD - TO - DATE $ ACTUAL	PERIOD - TO - DATE $ ESTIMATED	PERIOD - TO - DATE $ DIFFERENCE AMOUNT ($)	PERIOD - TO - DATE DIFFERENCE %
1 Jurisdictional Fuel Revenue	32,254,495.15	32,961,980	(707,485.34)	(2.15)	104,277,710.21	102,877,348	1,400,362.69	1.36
2 Fuel Adj. Revs. Not Applicable to Period:								
2a True-Up Provision	(3,996,375.00)	3,996,375	(7,992,750.00)	(200.00)	(11,989,120.00)	11,989,120	(23,978,240.00)	(200.00)
2b Incentive Provision	(210,177.00)	(210,177)	0.00	0.00	(630,529.00)	(630,529)	0.00	0.00
3 Juris. Fuel Revenue Applicable to Period	28,047,943.15	36,748,178	(8,700,234.85)	(23.68)	91,658,061.21	114,235,939	(22,577,877.79)	(19.76)
Adjusted Total Fuel & Net Power								
4 Transactions (Line A8)	28,038,169.89	32,171,208	(4,133,038.11)	(12.85)	98,986,974.30	103,419,048	(4,432,073.70)	(4.29)
5 Juris. Sales % of Total KWH Sales (Line B4)	97.2269	96.8253	0.4016	0.41	97.0528	96.7286	0.3242	0.34
Juris. Total Fuel & Net Power Transactions								
6 Adj. for Line Losses (C4*C5*1.0015)	27,301,534.37	31,196,593	(3,895,058.63)	(12.49)	96,206,291.15	100,184,374	(3,978,082.85)	(3.97)
True-Up Provision for the Month								
7 Over/(Under) Collection (C3-C6)	746,408.78	5,551,585	(4,805,176.22)	86.56	(4,548,229.94)	14,051,564	(18,599,793.94)	132.37
8 Interest Provision for the Month	(2,610.96)	(3,501)	890.04	25.42	(8,928.53)	(11,269)	2,340.47	20.77
9 Beginning True-Up & Interest Provision	(37,179,952.71)	(47,457,029)	10,277,076.29	21.66	(39,871,741.42)	(47,956,495)	8,084,753.58	16.86
10 True-Up Collected / (Refunded)	3,996,375.00	(3,996,375)	7,992,750.00	(200.00)	11,989,120.00	(11,989,120)	23,978,240.00	(200.00)
End of Period - Total Net True-Up, Before								
11 Adjustment (C7+C8+C9+C10)	(32,439,779.89)	(45,905,320)	13,465,540.11	29.33	(32,439,779.89)	(45,905,320)	13,465,540.11	29.33
12 Adjustment	(8,476.52)	0	(8,476.52)	100.00	(8,476.52)	0	(8,476.52)	100.00
13 End of Period - Total Net True-Up	(32,448,256.41)	(45,905,320)	13,457,063.59	29.31	(32,448,256.41)	(45,905,320)	13,457,063.59	29.31

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2015

		CURRENT MONTH			
		$		*DIFFERENCE*	
D.	*Interest Provision*	ACTUAL	ESTIMATED	AMOUNT ($)	%
1	BeginningTrue-Up Amount (C9)	(37,179,952.71)	(47,457,029)	10,277,076.29	(21.66)
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	(32,445,645.45)	(45,901,819)	13,456,173.55	(29.32)
3	Total of Beginning & Ending True-Up Amts.	(69,625,598.16)	(93,358,848)	23,733,249.84	(25.42)
4	Average True-Up Amount	(34,812,799.08)	(46,679,424)	11,866,624.92	(25.42)
	Interest Rate				
5	1st Day of Reporting Business Month	0.09	0.09	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.09	0.09	0.0000	
7	Total (D5+D6)	0.18	0.18	0.0000	
8	Annual Average Interest Rate	0.09	0.09	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0075	0.0075	0.0000	
10	Interest Provision (D4*D9)	(2,610.96)	(3,501)	890.04	(25.42)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0015		

Docket No. 160001-EI
2015 Final True-Up Filing
Exhibit CSB-1, Page 48 of 202

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2015

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	31,167	106,635	(75,468)	(70.77)	431,371	350,286	81,085	23.15
2	COAL	13,671,074	13,282,829	388,245	2.92	44,834,229	42,875,351	1,958,878	4.57
3	GAS	6,208,341	12,590,893	(6,382,552)	(50.69)	24,795,980	35,450,009	(10,654,029)	(30.05)
4	GAS (B.L.)	-	227,536	(227,536)	(100.00)	267,158	682,608	(415,450)	(60.86)
5	LANDFILL GAS	61,658	63,315	(1,657)	(2.62)	185,348	183,794	1,554	0.85
6	OIL - C.T.	0	0	0	0.00	122,560	0	122,560	100.00
7	TOTAL ($)	19,972,239	26,271,208	(6,298,969)	(23.98)	70,636,648	79,542,048	(8,905,400)	(11.20)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	349,173	335,796	13,377	3.98	1,084,621	1,050,808	33,813	3.22
10	GAS	234,256	346,339	(112,083)	(32.36)	940,481	948,992	(8,511)	(0.90)
11	LANDFILL GAS	2,013	2,100	(87)	(4.14)	6,140	6,096	44	0.72
12	OIL - C.T.	(7)	0	(7)	100.00	468	0	468	100.00
13	TOTAL (MWH)	585,435	684,235	(98,800)	(14.44)	2,031,710	2,005,896	25,814	1.29
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	369	856	(487)	(56.89)	4,660	2,803	1,857	66.25
15	COAL (TONS)	155,551	160,849	(5,298)	(3.29)	509,216	495,280	13,936	2.81
16	GAS (MCF) (1)	1,651,765	2,341,416	(689,651)	(29.45)	6,542,192	6,411,033	131,159	2.05
17	OIL - C.T. (BBL)	-	0	0	0.00	1,109	0	1,109	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	3,922,821	3,689,087	233,734	6.34	12,007,926	11,462,054	545,872	4.76
19	GAS - Generation (1)	1,695,960	2,341,416	(645,456)	(27.57)	6,653,178	6,411,033	242,145	3.78
20	OIL - C.T.	0	0	0	0.00	6,466	0	6,466	100.00
21	TOTAL (MMBTU)	5,618,781	6,030,503	(411,722)	(6.83)	18,667,571	17,873,087	794,484	4.45
	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	59.65	49.07	10.58	21.56	53.39	52.39	1.00	1.91
24	GAS	40.01	50.62	(10.61)	(20.96)	46.29	47.31	(1.02)	(2.16)
25	LANDFILL GAS	0.34	0.31	0.03	9.68	0.30	0.30	0.00	0.00
26	OIL - C.T.	0.00	0.00	0.00	0.00	0.02	0.00	0.02	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)	84.36	124.57	(40.21)	(32.28)	92.57	124.97	(32.40)	(25.93)
29	COAL ($/TON)	87.89	82.58	5.31	6.43	88.05	86.57	1.48	1.71
30	GAS ($/MCF) (1)	3.63	5.39	(1.76)	(32.65)	3.73	5.54	(1.81)	(32.67)
31	OIL - C.T. ($/BBL)	0.00	0.00	0.00	0.00	110.51	0.00	110.51	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	3.49	3.69	(0.20)	(5.42)	3.79	3.83	(0.04)	(1.04)
33	GAS - Generation (1)	3.53	5.29	(1.76)	(33.27)	3.62	5.44	(1.82)	(33.46)
34	OIL - C.T.	0.00	0.00	0.00	0.00	18.95	0.00	18.95	100.00
35	TOTAL ($/MMBTU)	3.51	4.31	(0.80)	(18.56)	3.74	4.41	(0.67)	(15.19)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	11,235	10,986	249	2.27	11,071	10,908	163	1.49
37	GAS - Generation (1)	7,442	6,874	568	8.26	7,219	6,876	343	4.99
38	OIL - C.T.	0	0	0	0.00	13,817	0	13,817	100.00
39	TOTAL (BTU/KWH)	9,737	8,915	822	9.22	9,303	9,012	291	3.23
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	3.92	4.06	(0.14)	(3.45)	4.20	4.18	0.02	0.48
41	GAS	2.65	3.64	(0.99)	(27.20)	2.64	3.74	(1.10)	(29.41)
42	LANDFILL GAS	3.06	3.02	0.04	1.32	3.02	3.01	0.01	0.33
43	OIL - C.T.	0.00	0.00	0.00	0.00	26.19	0.00	26.19	100.00
44	TOTAL (¢/KWH)	3.41	3.84	(0.43)	(11.20)	3.48	3.97	(0.49)	(12.34)

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: MARCH 2015

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2015	(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	36,301	65.1	100.0	65.1	11,215	Coal	17,896	11,375	407,125	1,583,226	4.36	88.47
2				0					Gas-G	0	1,022	0	0	0.00	0.00
3									Gas-S	0	1,022	0	0		0.00
4									Oil-S	10	137,660	58	1,282		128.20
5	Crist 5		75	(1,040)	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
6				-					Gas-G	0	1,022	0	0	0.00	0.00
7									Gas-S	0	1,022	0	0		0.00
8									Oil-S	0	137,660	0	0		0.00
9	Crist 6		299	28,795	13.0	87.1	60.1	9,653	Coal	11,923	11,657	277,963	1,054,793	3.66	88.47
10				0					Gas-G	78,555	1,022	80,284	349,353	0.00	0.00
11									Gas-S	0	1,022	0	0		0.00
12									Oil-S	0	137,660	0	0		0.00
13	Crist 7		475	187,050	53.0	100.0	53.0	10,850	Coal	88,011	11,530	2,029,532	7,786,342	4.16	88.47
14				0					Gas-G	2,152	1,022	2,199	9,569	0.00	4.45
15									Gas-S	0	1,022	0	0		0.00
16									Oil-S	3	137,660	20	435		145.00
17	Scholz 1		46	(220)	0.0	40.6	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	0	0	0		0.00
19	Scholz 2		46	8,158	23.9	26.5	58.7	12,635	Coal	4,620	11,155	103,079	0	0.00	0.00
20									Oil-S	8	0	48	905		113.13
21	Smith 1		162	56,530	47.0	100.0	47.0	11,205	Coal	28,173	11,241	633,395	2,449,941	4.33	86.96
22									Oil-S	44	138,865	255	3,536		80.36
23	Smith 2		195	27,129	18.7	100.0	40.1	11,804	Coal	13,938	11,488	320,241	1,212,042	4.47	86.96
24									Oil-S	261	138,865	1,517	21,076		80.77
25	Smith 3		558	221,243	53.4	70.4	79.4	7,293	Gas-G	1,571,058	1,027	1,613,477	5,633,259	2.55	3.59
26	Smith A	(2)	40	(7)	0.0	0.0	0.0	0	Oil	0	138,971	0	0	0.00	0.00
27	Other Generation			6,358									216,160	3.40	0.00
28	Perdido			2,013					Landfill Gas				61,658	3.06	0.00
29	Daniel 1	(1)	255	(473)	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
30									Oil-S	0	138,891	0	0		0.00
31	Daniel 2	(1)	255	13,598	7.2	70.9	33.5	10,982	Coal	8,367	8,924	149,332	635,426	4.67	75.94
32									Oil-S	44	138,891	256	3,932		89.36
33	Total		2,481	585,435	31.8	71.4	48.0	9,737				5,618,781	21,022,935	3.59	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

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)	
10,601	Inventory Adjustment - Crist	957,057	
(23,358)	Inventory Adjustment - Smith	(2,003,731)	
(4,620)	Inventory Adjustment - Scholz	-	
	Recoverable Fuel	19,972,239	3.41

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2015

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES :*								
2	UNITS (BBL)	894	856	38	4.44	4,408	2,803	1,605	57.26
3	UNIT COST ($/BBL)	77.43	122.82	(45.39)	(36.96)	73.90	122.78	(48.88)	(39.81)
4	AMOUNT ($)	69,218	105,132	(35,914)	(34.16)	325,757	344,154	(18,397)	(5.35)
5	*BURNED :*								
6	UNITS (BBL)	422	856	(434)	(50.70)	4,796	2,803	1,993	71.10
7	UNIT COST ($/BBL)	84.81	124.57	(39.76)	(31.92)	92.57	124.97	(32.40)	(25.93)
8	AMOUNT ($)	35,788	106,635	(70,847)	(66.44)	443,974	350,286	93,688	26.75
9	*ENDING INVENTORY :*								
10	UNITS (BBL)	6,607	7,166	(559)	(7.80)	6,607	7,166	(559)	(7.80)
11	UNIT COST ($/BBL)	105.76	125.95	(20.19)	(16.03)	105.76	125.95	(20.19)	(16.03)
12	AMOUNT ($)	698,766	902,545	(203,779)	(22.58)	698,766	902,545	(203,779)	(22.58)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES :*								
15	UNITS (TONS)	130,977	189,288	(58,311)	(30.81)	475,926	490,830	(14,904)	(3.04)
16	UNIT COST ($/TON)	87.95	80.15	7.80	9.73	86.80	79.77	7.03	8.81
17	AMOUNT ($)	11,519,587	15,172,142	(3,652,555)	(24.07)	41,309,032	39,151,352	2,157,680	5.51
18	*BURNED :*								
19	UNITS (TONS)	155,551	160,849	(5,298)	(3.29)	509,216	495,280	13,936	2.81
20	UNIT COST ($/TON)	87.91	82.58	5.33	6.45	88.07	86.57	1.50	1.73
21	AMOUNT ($)	13,675,096	13,282,829	392,267	2.95	44,846,296	42,875,351	1,970,945	4.60
22	*ENDING INVENTORY :*								
23	UNITS (TONS)	523,171	499,701	23,470	4.70	523,171	499,701	23,470	4.70
24	UNIT COST ($/TON)	80.07	76.57	3.50	4.57	80.07	76.57	3.50	4.57
25	AMOUNT ($)	41,888,110	38,259,717	3,628,393	9.48	41,888,110	38,259,717	3,628,393	9.48
26	DAYS SUPPLY	25	24	1	4.17				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES :*								
28	UNITS (MMBTU)	1,683,960	2,361,416	(677,456)	(28.69)	6,288,286	6,471,033	(182,747)	(2.82)
29	UNIT COST ($/MMBTU)	3.53	5.34	(1.81)	(33.90)	3.53	5.49	(1.96)	(35.70)
30	AMOUNT ($)	5,943,070	12,609,878	(6,666,808)	(52.87)	22,195,273	35,527,090	(13,331,817)	(37.53)
31	*BURNED :*								
32	UNITS (MMBTU)	1,695,960	2,361,416	(665,456)	(28.18)	6,714,788	6,471,033	243,755	3.77
33	UNIT COST ($/MMBTU)	3.53	5.34	(1.81)	(33.90)	3.63	5.49	(1.86)	(33.88)
34	AMOUNT ($)	5,991,431	12,609,878	(6,618,447)	(52.49)	24,377,636	35,527,090	(11,149,454)	(31.38)
35	*ENDING INVENTORY :*								
36	UNITS (MMBTU)	614,840	0	614,840	100.00	614,840	0	614,840	100.00
37	UNIT COST ($/MMBTU)	3.49	0.00	3.49	100.00	3.49	0.00	3.49	100.00
38	AMOUNT ($)	2,146,353	0	2,146,353	100.00	2,146,353	0	2,146,353	100.00
	OTHER - C.T. OIL								
39	*PURCHASES :*								
40	UNITS (BBL) *	0	0	0	0.00	894	0	894	100.00
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	68.86	0.00	69.00	100.00
42	AMOUNT ($)	0	0	0	0.00	61,561	0	61,561	100.00
43	*BURNED :*								
44	UNITS (BBL)	0	0	0	0.00	1,109	0	1,109	100.00
45	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	110.51	0.00	110.51	100.00
46	AMOUNT ($)	0	0	0	0.00	122,559	0	122,559	100.00
47	*ENDING INVENTORY :*								
48	UNITS (BBL)	6,843	7,143	(300)	(4.20)	6,843	7,143	(300)	(4.20)
49	UNIT COST ($/BBL)	110.48	117.59	(7.11)	(6.05)	110.48	117.59	(7.11)	(6.05)
50	AMOUNT ($)	756,028	839,922	(83,894)	(9.99)	756,028	839,922	(83,894)	(9.99)
51	DAYS SUPPLY	3	3	0	0.00				

SCHEDULE A-6
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POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2015

			CURRENT MONTH						
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	(a) ¢ / KWH FUEL COST	(b) ¢ / KWH TOTAL COST	(5) x (6)(a) TOTAL $ FOR FUEL ADJ.	(5) x (6)(b) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		14,838,000	0	14,838,000	2.92	3.28	433,000	486,000
2	Various	Economy Sales	8,955,000	0	8,955,000	2.99	3.33	268,000	298,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	21,000	21,000
4	TOTAL ESTIMATED SALES		23,793,000	0	23,793,000	3.03	3.38	722,000	805,000
	ACTUAL								
5	Southern Company Interchange		24,177,021	0	24,177,021	1.72	1.90	415,128	460,083
6	A.E.C.	External	7,292,027	0	7,292,027	2.23	2.68	162,388	195,360
7	AECI	External	0	0	0	0.00	0.00	0	0
8	AEP	External	0	0	0	0.00	0.00	0	0
9	BAM	External	0	0	0	0.00	0.00	0	0
10	CALPINE	External	0	0	0	0.00	0.00	0	0
11	CARGILE	External	223,168	0	223,168	2.37	3.68	5,283	8,214
12	DUKE PWR	External	218,863	0	218,863	1.68	2.26	3,684	4,944
13	EAGLE EN	External	460,802	0	460,802	1.95	3.02	8,984	13,933
14	ENDURE	External	0	0	0	0.00	0.00	0	0
15	EXELON	External	484,350	0	484,350	2.05	3.21	9,913	15,568
16	FPC	External	146,569	0	146,569	2.35	3.42	3,450	5,011
17	FPL	External	523,553	0	523,553	2.24	4.18	11,727	21,873
18	JPMVEC	External	597,549	0	597,549	2.50	3.05	14,954	18,249
19	MISO	External	356,680	0	356,680	2.00	4.32	7,137	15,412
20	MORGAN	External	1,220,185	0	1,220,185	1.80	2.91	22,012	35,528
21	NCEMC	External	469,345	0	469,345	1.85	2.92	8,696	13,707
22	NCMPA1	External	0	0	0	0.00	0.00	0	0
23	NOBLEAGP	External	26,528	0	26,528	1.59	2.80	422	743
24	NRG	External	0	0	0	0.00	0.00	0	0
25	OPC	External	3,316	0	3,316	1.88	2.90	62	96
26	ORLANDO	External	23,212	0	23,212	3.18	4.20	737	975
27	PJM	External	1,369,353	0	1,369,353	2.15	3.74	29,373	51,189
28	SCE&G	External	418,202	0	418,202	2.14	2.64	8,960	11,053
29	SEC	External	0	0	0	0.00	0.00	0	0
30	SEPA	External	492,095	0	492,095	1.76	2.59	8,646	12,730
31	SPP	External	0	0	0	0.00	0.00	0	0
32	TAL	External	159,510	0	159,510	1.90	3.74	3,029	5,961
33	TEA	External	3,119,857	0	3,119,857	1.90	3.02	59,405	94,200
34	TECO	External	474,132	0	474,132	2.21	3.45	10,484	16,347
35	TENASKA	External	7,627	0	7,627	2.82	3.20	215	244
36	TVA	External	134,504	0	134,504	2.43	4.04	3,272	5,434
37	WRI	External	271,912	0	271,912	1.75	2.81	4,767	7,640
38	Less: Flow-Thru Energy		(18,058,225)	0	(18,058,225)	2.08	2.08	(375,578)	(375,578)
39	SEPA		1,214,840	1,214,840	0	0.00	0.00	0	0
40	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	118,976	118,976
41	Other transactions including adj.		199,906,000	181,726,991	18,179,009	0.00	0.00	0	0
42	TOTAL ACTUAL SALES		225,732,975	182,941,831	42,791,144	0.24	0.28	546,126	638,919
43	Difference in Amount		201,939,975	182,941,831	18,998,144	(2.79)	(3.10)	(175,875)	(166,081)
44	Difference in Percent		848.74	0.00	79.85	(92.08)	(91.72)	(24.36)	(20.63)

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 40

SCHEDULE A-6
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POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2015

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		547,390,000	0	547,390,000	2.99	3.37	16,364,000	18,428,000
2	Various	Economy Sales	30,806,000	0	30,806,000	3.07	3.37	947,000	1,038,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	89,000	89,000
4	TOTAL ESTIMATED SALES		578,196,000	0	578,196,000	3.01	3.38	17,400,000	19,555,000
	ACTUAL								
5	Southern Company Interchange		701,892,262	0	701,892,262	2.92	3.18	20,472,694	22,328,318
6	A.E.C.	External	24,184,491	0	24,184,491	2.36	2.88	571,755	695,365
7	AECI	External	401,439	0	401,439	2.37	2.99	9,528	11,994
8	AEP	External	0	0	0	0.00	0.00	0	0
9	BAM	External	5,903	0	5,903	2.00	3.27	118	193
10	CALPINE	External	0	0	0	0.00	0.00	0	0
11	CARGILE	External	574,869	0	574,869	2.47	3.41	14,202	19,626
12	DUKE PWR	External	2,153,566	0	2,153,566	2.26	3.56	48,730	76,600
13	EAGLE EN	External	1,508,537	0	1,508,537	2.67	4.14	40,214	62,506
14	ENDURE	External	41,782	0	41,782	2.40	4.13	1,003	1,724
15	EXELON	External	1,576,602	0	1,576,602	2.52	3.50	39,808	55,145
16	FPC	External	232,389	0	232,389	2.23	3.20	5,184	7,436
17	FPL	External	722,523	0	722,523	2.19	4.02	15,807	29,036
18	JPMVEC	External	694,844	0	694,844	2.48	3.13	17,211	21,783
19	MISO	External	1,829,335	0	1,829,335	1.98	3.12	36,228	57,000
20	MORGAN	External	2,956,278	0	2,956,278	2.17	2.93	64,105	86,472
21	NCEMC	External	1,306,951	0	1,306,951	2.31	3.23	30,151	42,196
22	NCMPA1	External	1,658	0	1,658	1.61	2.80	27	46
23	NOBLEAGP	External	26,528	0	26,528	1.59	2.80	422	743
24	NRG	External	0	0	0	0.00	0.00	0	0
25	OPC	External	456,821	0	456,821	2.61	3.82	11,907	17,472
26	ORLANDO	External	33,160	0	33,160	3.07	4.20	1,017	1,393
27	PJM	External	5,239,096	0	5,239,096	2.33	3.97	121,984	207,919
28	SCE&G	External	2,465,572	0	2,465,572	3.22	3.88	79,401	95,674
29	SEC	External	41,450	0	41,450	2.89	3.68	1,198	1,524
30	SEPA	External	2,766,429	0	2,766,429	2.05	3.14	56,642	86,760
31	SPP	External	0	0	0	0.00	0.00	0	0
32	TAL	External	159,510	0	159,510	1.90	3.74	3,029	5,961
33	TEA	External	8,076,727	0	8,076,727	2.11	3.25	170,758	262,392
34	TECO	External	608,501	0	608,501	2.18	3.39	13,249	20,621
35	TENASKA	External	7,627	0	7,627	2.82	3.20	215	244
36	TVA	External	2,909,077	0	2,909,077	2.32	3.89	67,380	113,269
37	WRI	External	995,728	0	995,728	2.16	2.91	21,549	29,003
38	Less: Flow-Thru Energy		(59,493,914)	0	(59,493,914)	2.28	2.28	(1,356,445)	(1,356,445)
39	SEPA		3,551,592	3,551,592	0	0.00	0.00	0	0
40	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	352,592	352,591
41	Other transactions including adj.		697,628,932	543,800,213	153,828,719	0.00	0.00	0	0
42	TOTAL ACTUAL SALES		1,405,556,265	547,351,805	858,204,460	1.49	1.64	20,911,661	22,981,970
43	Difference in Amount		827,360,265	547,351,805	280,008,460	(1.52)	(1.74)	3,511,661	3,426,970
44	Difference in Percent		143.09	0.00	48.43	(50.50)	(51.48)	20.18	17.52

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 40

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: MARCH 2015

(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: MARCH 2015

CURRENT MONTH

	(1) PURCHASED FROM:	(2) TYPE AND SCHEDULE	(3) TOTAL KWH PURCHASED	(4) KWH FOR OTHER UTILITIES	(5) KWH FOR INTERRUPTIBLE	(6) KWH FOR FIRM	(7) ¢/KWH (A) FUEL COST	(7) ¢/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	5,564,000	0	0	0	3.52	3.52	195,760
3	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
4	Ascend Performance Materials	COG 1	13,807,000	0	0	0	2.23	2.23	307,860
5	International Paper	COG 1	121,000	0	0	0	2.26	2.26	2,729
6	TOTAL		19,492,000	0	0	0	2.60	2.60	506,349

PERIOD-TO-DATE

	(1) PURCHASED FROM:	(2) TYPE AND SCHEDULE	(3) TOTAL KWH PURCHASED	(4) KWH FOR OTHER UTILITIES	(5) KWH FOR INTERRUPTIBLE	(6) KWH FOR FIRM	(7) ¢/KWH (A) FUEL COST	(7) ¢/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	9,128,000	0	0	0	3.52	3.52	321,156
3	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	11
4	Ascend Performance Materials	COG 1	44,789,000	0	0	0	2.81	2.81	1,258,965
5	International Paper	COG 1	539,000	0	0	0	2.83	2.83	15,259
6	TOTAL		54,456,000	0	0	0	2.93	2.93	1,595,392

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2015

	(1) PURCHASED FROM	CURRENT MONTH (2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	PERIOD - TO - DATE (5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	157,067,000	3.28	5,148,000	349,417,000	3.36	11,731,000
2	Economy Energy	5,115,000	3.38	173,000	12,026,000	3.56	428,000
3	Other Purchases	2,696,000	48.26	1,301,000	795,093,000	3.66	29,118,000
4	TOTAL ESTIMATED PURCHASES	164,878,000	4.02	6,622,000	1,156,536,000	3.57	41,277,000
	ACTUAL						
5	Southern Company Interchange	258,623,011	2.46	6,356,373	476,929,964	2.65	12,623,077
6	Non-Associated Companies	39,662,741	0.45	179,282	145,419,657	1.11	1,612,375
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	0	0.00	63,516	848,799,000	2.86	24,316,351
9	Other Wheeled Energy	24,109,000	0.00	N/A	185,577,000	0.00	N/A
10	Other Transactions	145,581,044	0.01	14,718	392,970,602	0.02	60,129
11	Less: Flow-Thru Energy	(18,058,225)	2.26	(407,582)	(59,493,914)	2.51	(1,495,622)
12	TOTAL ACTUAL PURCHASES	449,917,571	1.38	6,206,307	1,990,202,309	1.86	37,116,310
13	Difference in Amount	285,039,571	(2.64)	(415,693)	833,666,309	(1.71)	(4,160,690)
14	Difference in Percent	172.88	(65.67)	(6.28)	72.08	(47.90)	(10.08)

2015 CAPACITY CONTRACTS
GULF POWER COMPANY

	(A)	(B)		(C) JAN		(D) FEB		(E) MAR		(F) APR		(G) MAY		(H) JUN		(I)
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	SUBTOTAL
1 Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0.0	0	0.0	0	0.0	0							0
SUBTOTAL				0.0	$ -	0.0	$ -	0.0	$ -	0.0	$ -	0.0	$ -	0.0	$ -	$ -
B. CONFIDENTIAL CAPACITY CONTRACTS																
Power Purchase Agreements & Other																
1 Confidential Agreements	Other	Varies	Varies	885.0	7,387,528	885.0	7,392,119	885.0	7,387,234							
SUBTOTAL					$ 7,387,528		$ 7,392,119		$ 7,387,234	$ -		$ -		$ -		$ 22,166,881
																$ 22,166,881
TOTAL					**$ 7,387,528**		**$ 7,392,119**		**$ 7,387,234**	**$ -**		**$ -**		**$ -**		**$ 22,166,881**

Docket No. 160001-EI
2015 Final True-Up Filing
Exhibit CSB-1, Page 57 of 202

2015 CAPACITY CONTRACTS
GULF POWER COMPANY

	(J)	(K)		(L)		(M)		(N)		(O)		(P)		(Q)		(R)
				JUL		AUG		SEP		OCT		NOV		DEC		YTD
A. CONTRACT/COUNTERPARTY	CONTRACT TYPE	TERM Start	End	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	$
1 Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice													0
SUBTOTAL				0.0	$ -	0.0	$ -	0.0	$ -	0.0	$ -	0.0	$ -	0.0	$ -	$ -
B. CONFIDENTIAL CAPACITY CONTRACTS																
Power Purchase Agreements & Other																
1 Confidential Agreements	Other	Varies	Varies													22,166,881
SUBTOTAL				$	-	$	-	$	-	$	-	$	-	$	-	$ 22,166,881
TOTAL				$	-	$	-	$	-	$	-	$	-	$	-	**$ 22,166,881**

Docket No. 160001-EI
2015 Final True-Up Filing
Exhibit CSB-1, Page 58 of 202

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 150001-EI

MONTHLY FUEL FILING

APRIL 2015

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
APRIL 2015

		DOLLARS		DIFFERENCE		KWH		DIFFERENCE		CENTS/KWH		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)	19,053,619	28,262,018	(9,208,399)	(32.58)	540,142,000	736,404,000	(196,262,000)	(26.65)	3.5275	3.8378	(0.31)	(8.09)
2	Hedging Settlement Costs (A2)	3,488,270	0	3,488,270	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	8,509	0	8,509	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	22,550,398	28,262,018	(5,711,620)	(20.21)	540,142,000	736,404,000	(196,262,000)	(26.65)	4.1749	3.8378	0.34	8.78
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	10,027,038	5,796,000	4,231,038	73.00	481,657,861	134,795,000	346,862,861	257.33	2.0818	4.2999	(2.22)	(51.58)
9	Energy Cost of Schedule E Economy Purch. (A9)	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	436,232	0	436,232	100.00	15,943,000	0	15,943,000	100.00	2.7362	0.0000	2.74	0.00
12	TOTAL COST OF PURCHASED POWER	10,463,270	5,796,000	4,667,270	80.53	497,600,861	134,795,000	362,805,861	269.15	2.1027	4.2999	(2.20)	(51.10)
13	Total Available MWH (Line 5 + Line 12)	33,013,668	34,058,018	(1,044,350)	(3.07)	1,037,742,861	871,199,000	166,543,861	19.12				
14	Fuel Cost of Economy Sales (A6)	(133,718)	(274,000)	140,282	(51.20)	(6,515,320)	(8,789,000)	2,273,680	(25.87)	(2.0524)	(3.1175)	1.07	34.17
15	Gain on Economy Sales (A6)	(17,658)	(21,000)	3,342	(15.91)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(412,653)	(928,000)	515,347	(55.53)	(159,587,637)	(35,669,000)	(123,918,637)	347.41	(0.2586)	(2.6017)	2.34	90.06
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(564,029)	(1,223,000)	658,971	(53.88)	(166,102,957)	(44,458,000)	(121,644,957)	273.62	(0.3396)	(2.7509)	2.41	87.65
18	Net Inadvertant Interchange	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	32,449,639	32,835,018	(385,379)	(1.17)	871,639,904	826,741,000	44,898,904	5.43	3.7228	3.9716	(0.25)	(6.26)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	68,737	63,744	4,993	7.83	1,846,382	1,605,000	241,382	15.04	3.7228	3.9716	(0.25)	(6.26)
22	T & D Losses *	1,402,531	1,503,290	(100,759)	(6.70)	37,674,098	37,851,000	(176,902)	(0.47)	3.7228	3.9716	(0.25)	(6.26)
23	TERRITORIAL KWH SALES	32,449,638	32,835,018	(385,379)	(1.17)	832,119,424	787,285,000	44,834,424	5.69	3.8996	4.1707	(0.27)	(6.50)
24	Wholesale KWH Sales	876,075	1,021,694	(145,619)	(14.25)	22,465,423	24,497,000	(2,031,577)	(8.29)	3.8997	4.1707	(0.27)	(6.50)
25	Jurisdictional KWH Sales	31,573,563	31,813,324	(239,761)	(0.75)	809,654,001	762,788,000	46,866,001	6.14	3.8996	4.1707	(0.27)	(6.50)
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	31,620,923	31,861,044	(240,121)	(0.75)	809,654,001	762,788,000	46,866,001	6.14	3.9055	4.1769	(0.27)	(6.50)
28	TRUE-UP	3,996,375	3,996,375	0	0.00	809,654,001	762,788,000	46,866,001	6.14	0.4936	0.5239	(0.03)	(5.78)
29	TOTAL JURISDICTIONAL FUEL COST	35,617,298	35,857,419	(240,121)	(0.67)	809,654,001	762,788,000	46,866,001	6.14	4.3991	4.7008	(0.30)	(6.42)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.4023	4.7042	(0.30)	(6.42)
32	GPIF Reward / (Penalty)	210,328	210,328	0	0.00	809,654,001	762,788,000	46,866,001	6.14	0.0260	0.0276	(0.00)	(5.80)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.4283	4.7318	(0.30)	(6.41)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.428	4.732		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: APRIL 2015

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 19,053,619
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	8,509
4	Hedging Settlement Costs	Schedule A-2, Line A-5	3,488,270
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	10,027,038
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	436,232
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(564,029)
10	Total Fuel and Net Power Transactions		$ 32,449,639

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
APRIL 2015
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)	89,690,266	107,804,066	(18,113,800)	(16.80)	2,571,852,000	2,742,300,000	(170,448,000)	(6.22)	3.4874	3.9312	(0.44)	(11.29)
2	Hedging Settlement Costs (A2)	14,163,430	0	14,163,430	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	(116,366)	0	(116,366)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	103,737,330	107,804,066	(4,066,736)	(3.77)	2,571,852,000	2,742,300,000	(170,448,000)	(6.22)	4.0336	3.9312	0.10	2.60
6	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
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	47,143,347	47,073,000	70,347	0.15	2,471,860,170	1,291,331,000	1,180,529,170	91.42	1.9072	3.6453	(1.74)	(47.68)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	2,031,623	0	2,031,623	100.00	70,399,000	0	70,399,000	100.00	2.8859	0.0000	2.89	0.00
12	TOTAL COST OF PURCHASED POWER	49,174,970	47,073,000	2,101,970	4.47	2,542,259,170	1,291,331,000	1,250,928,170	96.87	1.9343	3.6453	(1.71)	(46.94)
13	Total Available MWH (Line 5 + Line 12)	152,912,300	154,877,066	(1,964,766)	(1.27)	5,114,111,170	4,033,631,000	1,080,480,170	26.79				
14	Fuel Cost of Economy Sales (A6)	(1,576,538)	(1,221,000)	(355,538)	29.12	(68,492,713)	(39,595,000)	(28,897,713)	72.98	(2.3018)	(3.0837)	0.78	25.36
15	Gain on Economy Sales (A6)	(370,249)	(110,000)	(260,249)	236.59	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(19,528,902)	(17,292,000)	(2,236,902)	12.94	(1,503,166,509)	(583,059,000)	(920,107,509)	157.81	(1.2992)	(2.9657)	1.67	56.19
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(21,475,689)	(18,623,000)	(2,852,689)	15.32	(1,571,659,222)	(622,654,000)	(949,005,222)	152.41	(1.3664)	(2.9909)	1.62	54.31
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	131,436,611	136,254,066	(4,817,455)	(3.54)	3,542,451,948	3,410,977,000	131,474,948	3.85	3.7103	3.9946	(0.28)	(7.12)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	274,255	285,945	(11,690)	(4.09)	7,391,729	7,158,300	233,429	3.26	3.7103	3.9946	(0.28)	(7.12)
22	T & D Losses *	6,376,219	6,448,870	(72,651)	(1.13)	171,851,837	161,439,700	10,412,137	6.45	3.7103	3.9946	(0.28)	(7.12)
23	TERRITORIAL KWH SALES	131,436,612	136,254,066	(4,817,454)	(3.54)	3,363,208,382	3,242,379,000	120,829,382	3.73	3.9081	4.2023	(0.29)	(7.00)
24	Wholesale KWH Sales	3,800,851	4,406,420	(605,569)	(13.74)	97,061,727	104,812,000	(7,750,273)	(7.39)	3.9159	4.2041	(0.29)	(6.86)
25	Jurisdictional KWH Sales	127,635,761	131,847,646	(4,211,885)	(3.19)	3,266,146,655	3,137,567,000	128,579,655	4.10	3.9078	4.2022	(0.29)	(7.01)
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	127,827,214	132,045,418	(4,218,204)	(3.19)	3,266,146,655	3,137,567,000	128,579,655	4.10	3.9137	4.2085	(0.29)	(7.00)
28	TRUE-UP	15,985,495	15,985,495	0	0.00	3,266,146,655	3,137,567,000	128,579,655	4.10	0.4894	0.5095	(0.02)	(3.95)
29	TOTAL JURISDICTIONAL FUEL COST	143,812,709	148,030,913	(4,218,204)	(2.85)	3,266,146,655	3,137,567,000	128,579,655	4.10	4.4031	4.7180	(0.31)	(6.67)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.4063	4.7214	(0.32)	(6.67)
32	GPIF Reward / (Penalty)	841,314	841,314	0	0.00	3,266,146,655	3,137,567,000	128,579,655	4.10	0.0258	0.0268	(0.00)	(3.73)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.4321	4.7482	(0.32)	(6.66)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.432	4.748		

* 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: APRIL 2015

		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	18,861,038.78	28,060,175	(9,199,136.22)	(32.78)	88,814,434.36	106,996,696	(18,182,261.64)	(16.99)
1a	Other Generation	192,579.78	201,843	(9,263.22)	(4.59)	875,832.09	807,370	68,462.09	8.48
2	Fuel Cost of Power Sold	(564,028.47)	(1,223,000)	658,971.53	53.88	(21,475,689.81)	(18,623,000)	(2,852,689.81)	(15.32)
3	Fuel Cost - Purchased Power	10,027,037.45	5,796,000	4,231,037.45	73.00	47,143,346.79	47,073,000	70,346.79	0.15
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	436,231.68	0	436,231.68	100.00	2,031,623.69	0	2,031,623.69	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	3,488,270.00	0	3,488,270.00	100.00	14,163,430.00	0	14,163,430.00	100.00
6	Total Fuel & Net Power Transactions	32,441,129.22	32,835,018	(393,888.78)	(1.20)	131,552,977.12	136,254,066	(4,701,088.88)	(3.45)
7	AdjustmentsTo Fuel Cost*	8,508.94	0	8,508.94	100.00	(116,365.26)	0	(116,365.26)	100.00
8	Adj. Total Fuel & Net Power Transactions	32,449,638.16	32,835,018	(385,379.84)	(1.17)	131,436,611.86	136,254,066	(4,817,454.14)	(3.54)
B.	*KWH Sales*								
1	Jurisdictional Sales	809,654,001	762,788,000	46,866,001	6.14	3,266,146,655	3,137,567,000	128,579,655	4.10
2	Non-Jurisdictional Sales	22,465,423	24,497,000	(2,031,577)	(8.29)	97,061,727	104,812,000	(7,750,273)	(7.39)
3	Total Territorial Sales	832,119,424	787,285,000	44,834,424	5.69	3,363,208,382	3,242,379,000	120,829,382	3.73
4	Juris. Sales as % of Total Terr. Sales	97.3002	96.8884	0.4118	0.43	97.1140	96.7674	0.3466	0.36

**(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: APRIL 2015

		CURRENT MONTH				PERIOD - TO - DATE			
		$		*DIFFERENCE*		$		*DIFFERENCE*	
		ACTUAL	**ESTIMATED**	**AMOUNT ($)**	**%**	**ACTUAL**	**ESTIMATED**	**AMOUNT ($)**	**%**
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	33,994,639.02	33,044,593	950,045.75	2.88	138,272,349.23	135,921,941	2,350,408.44	1.73
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(3,996,375.00)	3,996,375	(7,992,750.00)	(200.00)	(15,985,495.00)	15,985,495	(31,970,990.00)	(200.00)
2b	Incentive Provision	(210,177.00)	(210,177)	0.00	0.00	(840,706.00)	(840,706)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	29,788,087.02	36,830,791	(7,042,703.98)	(19.12)	121,446,148.23	151,066,730	(29,620,581.77)	(19.61)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	32,449,638.16	32,835,018	(385,379.84)	(1.17)	131,436,612.46	136,254,066	(4,817,453.54)	(3.54)
5	Juris. Sales % of Total KWH Sales (Line B4)	97.3002	96.8884	0.4118	0.43	97.1140	96.7674	0.3466	0.36
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	31,620,923.17	31,861,044	(240,120.83)	(0.75)	127,827,214.32	132,045,418	(4,218,203.68)	(3.19)
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(1,832,836.15)	4,969,747	(6,802,583.15)	136.88	(6,381,066.09)	19,021,311	(25,402,377.09)	133.55
8	Interest Provision for the Month	(1,976.09)	(2,861)	884.91	30.93	(10,904.62)	(14,130)	3,225.38	22.83
9	Beginning True-Up & Interest Provision	(32,448,256.41)	(45,905,320)	13,457,063.59	29.31	(39,871,741.42)	(47,956,495)	8,084,753.58	16.86
10	True-Up Collected / (Refunded)	3,996,375.00	(3,996,375)	7,992,750.00	(200.00)	15,985,495.00	(15,985,495)	31,970,990.00	(200.00)
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(30,286,693.65)	(44,934,809)	14,648,115.35	32.60	(30,278,217.13)	(44,934,809)	14,656,591.87	32.62
12	Adjustment	1,605.26	0	1,605.26	100.00	(6,871.26)	0	(6,871.26)	100.00
13	End of Period - Total Net True-Up	(30,285,088.39)	(44,934,809)	14,649,720.61	32.60	(30,285,088.39)	(44,934,809)	14,649,720.61	32.60

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2015

		CURRENT MONTH			
		$		*DIFFERENCE*	
		ACTUAL	**ESTIMATED**	**AMOUNT ($)**	**%**
D.	*Interest Provision*				
1	Beginning True-Up Amount (C9)	(32,448,256.41)	(45,905,320)	13,457,063.59	(29.31)
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(30,284,717.56)	(44,931,948)	14,647,230.44	(32.60)
3	Total of Beginning & Ending True-Up Amts.	(62,732,973.97)	(90,837,268)	28,104,294.03	(30.94)
4	Average True-Up Amount	(31,366,486.99)	(45,418,634)	14,052,147.01	(30.94)
5	Interest Rate 1st Day of Reporting Business Month	0.09	0.09	0.0000	
6	Interest Rate 1st Day of Subsequent Business Month	0.06	0.06	0.0000	
7	Total (D5+D6)	0.15	0.15	0.0000	
8	Annual Average Interest Rate	0.08	0.08	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0063	0.0063	0.0000	
10	Interest Provision (D4*D9)	(1,976.09)	(2,861)	884.91	(30.93)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0015		

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2015

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	280,349	105,024	175,325	166.94	711,720	455,310	256,410	56.32
2	COAL	9,864,863	17,754,612	(7,889,749)	(44.44)	54,699,092	60,629,963	(5,930,871)	(9.78)
3	GAS	8,706,491	10,133,611	(1,427,119)	(14.08)	33,502,471	45,583,620	(12,081,148)	(26.50)
4	GAS (B.L.)	99,978	207,536	(107,558)	(51.83)	367,136	890,144	(523,008)	(58.76)
5	LANDFILL GAS	65,533	61,235	4,298	7.02	250,881	245,029	5,852	2.39
6	OIL - C.T.	36,405	0	36,405	100.00	158,965	0	158,965	100.00
7	TOTAL ($)	19,053,619	28,262,018	(9,208,399)	(32.58)	89,690,266	107,804,066	(18,113,799)	(16.80)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	219,504	458,004	(238,500)	(52.07)	1,304,125	1,508,812	(204,687)	(13.57)
10	GAS	318,484	276,369	42,115	15.24	1,258,965	1,225,361	33,604	2.74
11	LANDFILL GAS	2,139	2,031	108	5.32	8,279	8,127	152	1.87
12	OIL - C.T.	15	0	15	100.00	483	0	483	100.00
13	TOTAL (MWH)	540,142	736,404	(196,262)	(26.65)	2,571,852	2,742,300	(170,448)	(6.22)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	3,254	842	2,412	286.46	7,914	3,645	4,269	117.12
15	COAL (TONS)	119,283	226,671	(107,388)	(47.38)	628,499	721,951	(93,452)	(12.94)
16	GAS (MCF) (1)	1,607,687	1,857,370	(249,683)	(13.44)	8,149,879	8,268,403	(118,524)	(1.43)
17	OIL - C.T. (BBL)	330	0	330	100.00	1,439	0	1,439	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	2,615,968	4,971,249	(2,355,281)	(47.38)	14,623,895	16,433,303	(1,809,408)	(11.01)
19	GAS - Generation (1)	1,637,514	1,857,370	(219,856)	(11.84)	8,290,692	8,268,403	22,289	0.27
20	OIL - C.T.	1,923	0	1,923	100.00	8,389	0	8,389	100.00
21	TOTAL (MMBTU)	4,255,406	6,828,619	(2,573,213)	(37.68)	22,922,976	24,701,706	(1,778,730)	(7.20)
	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	40.64	62.19	(21.55)	(34.65)	50.71	55.02	(4.31)	(7.83)
24	GAS	58.96	37.53	21.43	57.10	48.95	44.68	4.27	9.56
25	LANDFILL GAS	0.40	0.28	0.12	42.86	0.32	0.30	0.02	6.67
26	OIL - C.T.	0.00	0.00	0.00	0.00	0.02	0.00	0.02	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)	86.16	124.73	(38.57)	(30.92)	89.93	124.91	(34.98)	(28.00)
29	COAL ($/TON)	82.70	78.33	4.37	5.58	87.03	83.98	3.05	3.63
30	GAS ($/MCF) (1)	5.36	5.46	(0.10)	(1.83)	4.05	5.52	(1.47)	(26.63)
31	OIL - C.T. ($/BBL)	110.32	0.00	110.32	100.00	110.47	0.00	110.47	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	3.92	3.63	0.29	7.99	3.81	3.77	0.04	1.06
33	GAS - Generation (1)	5.20	5.35	(0.15)	(2.80)	3.94	5.42	(1.48)	(27.31)
34	OIL - C.T.	18.93	0.00	18.93	100.00	18.95	0.00	18.95	100.00
35	TOTAL ($/MMBTU)	4.42	4.10	0.32	7.80	3.86	4.32	(0.46)	(10.65)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	11,918	10,854	1,064	9.80	11,214	10,892	322	2.96
37	GAS - Generation (1)	5,229	6,858	(1,629)	(23.75)	6,714	6,872	(158)	(2.30)
38	OIL - C.T.	128,215	0	128,215	100.00	17,369	0	17,369	100.00
39	TOTAL (BTU/KWH)	7,988	9,369	(1,381)	(14.74)	9,027	9,108	(81)	(0.89)
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	4.67	3.94	0.73	18.53	4.28	4.11	0.17	4.14
41	GAS	2.73	3.67	(0.94)	(25.61)	2.66	3.72	(1.06)	(28.49)
42	LANDFILL GAS	3.06	3.02	0.04	1.32	3.03	3.01	0.02	0.66
43	OIL - C.T.	242.70	0.00	242.70	100.00	32.91	0.00	32.91	100.00
44	TOTAL (¢/KWH)	3.53	3.84	(0.31)	(8.07)	3.49	3.93	(0.44)	(11.20)

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: APRIL 2015

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2015	(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	22,803	42.2	73.3	57.6	11,914	Coal	11,896	11,418	271,664	1,051,974	4.61	88.43
2				0					Gas-G	9,424	1,019	9,604	94,467	0.00	10.02
3									Gas-S	6,613	1,019	6,739	66,288		10.02
4									Oil-S	93	137,660	540	11,939		128.38
5	Crist 5		75	(1,116)	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
6				-					Gas-G	0	1,019	0	0	0.00	0.00
7									Gas-S	0	1,019	0	0		0.00
8									Oil-S	0	137,660	0	0		0.00
9	Crist 6		299	(1,112)	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
10				0					Gas-G	0	1,019	0	0	0.00	0.00
11									Gas-S	0	1,019	0	0		0.00
12									Oil-S	0	137,660	0	0		0.00
13	Crist 7		475	78,118	22.8	46.5	48.5	11,229	Coal	38,361	11,433	877,161	3,392,201	4.34	88.43
14				0					Gas-G	14,165	1,019	14,433	141,976	0.00	10.02
15									Gas-S	3,361	1,019	3,425	33,689		10.02
16									Oil-S	54	137,660	1	6,947		128.65
17	Scholz 1		46	(127)	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	0	0	0		0.00
19	Scholz 2		46	(69)	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	0	0	0		0.00
21	Smith 1		162	27,645	23.7	100.0	44.6	12,110	Coal	14,810	11,302	334,777	1,253,209	4.53	84.62
22									Oil-S	73	139,126	427	5,957		81.60
23	Smith 2		195	(438)	0.0	50.0	0.0	0	Coal	0	0	0	0	0.00	0.00
24									Oil-S	0	139,126	0	0		0.00
25	Smith 3		479	311,142	90.2	99.5	94.7	5,186	Gas-G	1,574,124	1,025	1,613,477	8,277,468	2.66	5.26
26	Smith A	(2)	32	15	0.1	49.7	38.0	128,200	Oil	330	138,971	1,923	36,405	242.70	110.32
27	Other Generation			5,302									192,580	3.63	0.00
28	Perdido			2,139					Landfill Gas				65,533	3.06	0.00
29	Daniel 1	(1)	255	49,112	26.7	74.3	48.9	12,327	Coal	29,698	10,193	605,407	2,285,034	4.65	76.94
30									Oil-S	2,311	138,312	13,420	194,616		84.21
31	Daniel 2	(1)	255	46,728	25.5	98.8	47.7	10,662	Coal	24,518	10,160	498,209	1,886,466	4.04	76.94
32									Oil-S	723	138,312	4,199	60,891		84.22
33	Total		2,394	540,142	31.3	61.4	44.2	7,988				4,255,406	19,057,641	3.53	

Notes & Adjust.: (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

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)	
	Recoverable Fuel	19,053,619	3.53

Docket No. 160001-EI
2015 Final True-Up Filing
Exhibit CSB-1, Page 67 of 202

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2015

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES :*								
2	UNITS (BBL)	2,205	842	1,363	161.88	6,613	3,645	2,968	81.43
3	UNIT COST ($/BBL)	76.41	122.75	(46.34)	(37.75)	74.74	122.77	(48.03)	(39.12)
4	AMOUNT ($)	168,482	103,354	65,128	63.01	494,239	447,508	46,731	10.44
5	*BURNED :*								
6	UNITS (BBL)	3,467	842	2,625	311.76	8,263	3,645	4,618	126.69
7	UNIT COST ($/BBL)	87.49	124.73	(37.24)	(29.86)	90.44	124.91	(34.47)	(27.60)
8	AMOUNT ($)	303,318	105,024	198,294	188.81	747,292	455,310	291,982	64.13
9	*ENDING INVENTORY :*								
10	UNITS (BBL)	5,346	7,166	(1,820)	(25.40)	5,346	7,166	(1,820)	(25.40)
11	UNIT COST ($/BBL)	105.49	125.72	(20.23)	(16.09)	105.49	125.72	(20.23)	(16.09)
12	AMOUNT ($)	563,930	900,875	(336,945)	(37.40)	563,930	900,875	(336,945)	(37.40)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES :*								
15	UNITS (TONS)	152,927	177,180	(24,253)	(13.69)	628,853	668,010	(39,157)	(5.86)
16	UNIT COST ($/TON)	88.18	76.23	11.95	15.68	87.13	78.83	8.30	10.53
17	AMOUNT ($)	13,484,499	13,505,854	(21,355)	(0.16)	54,793,531	52,657,206	2,136,325	4.06
18	*BURNED :*								
19	UNITS (TONS)	119,283	226,671	(107,388)	(47.38)	628,499	721,951	(93,452)	(12.94)
20	UNIT COST ($/TON)	82.74	78.33	4.41	5.63	87.06	83.98	3.08	3.67
21	AMOUNT ($)	9,868,884	17,754,612	(7,885,728)	(44.42)	54,715,180	60,629,963	(5,914,783)	(9.76)
22	*ENDING INVENTORY :*								
23	UNITS (TONS)	556,816	450,210	106,606	23.68	556,816	450,210	106,606	23.68
24	UNIT COST ($/TON)	81.72	75.54	6.18	8.18	81.72	75.54	6.18	8.18
25	AMOUNT ($)	45,503,725	34,010,959	11,492,766	33.79	45,503,725	34,010,959	11,492,766	33.79
26	DAYS SUPPLY	27	22	5	22.73				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES :*								
28	UNITS (MMBTU)	2,431,227	1,872,370	558,857	29.85	8,719,513	8,343,403	376,110	4.51
29	UNIT COST ($/MMBTU)	3.83	5.42	(1.59)	(29.34)	3.61	5.47	(1.86)	(34.00)
30	AMOUNT ($)	9,307,040	10,139,304	(832,264)	(8.21)	31,502,313	45,666,394	(14,164,081)	(31.02)
31	*BURNED :*								
32	UNITS (MMBTU)	2,276,571	1,872,370	404,201	21.59	8,991,359	8,343,403	647,956	7.77
33	UNIT COST ($/MMBTU)	3.78	5.42	(1.64)	(30.26)	3.67	5.47	(1.80)	(32.91)
34	AMOUNT ($)	8,613,139	10,139,304	(1,526,165)	(15.05)	32,990,775	45,666,394	(12,675,619)	(27.76)
35	*ENDING INVENTORY :*								
36	UNITS (MMBTU)	769,496	0	769,496	100.00	769,496	0	769,496	100.00
37	UNIT COST ($/MMBTU)	3.69	0.00	3.69	100.00	3.69	0.00	3.69	100.00
38	AMOUNT ($)	2,840,254	0	2,840,254	100.00	2,840,254	0	2,840,254	100.00
	OTHER - C.T. OIL								
39	*PURCHASES :*								
40	UNITS (BBL) *	0	0	0	0.00	894	0	894	100.00
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	68.86	0.00	69.00	100.00
42	AMOUNT ($)	0	0	0	0.00	61,561	0	61,561	100.00
43	*BURNED :*								
44	UNITS (BBL)	330	0	330	100.00	1,439	0	1,439	100.00
45	UNIT COST ($/BBL)	110.32	0.00	110.32	100.00	110.47	0.00	110.47	100.00
46	AMOUNT ($)	36,405	0	36,405	100.00	158,964	0	158,964	100.00
47	*ENDING INVENTORY :*								
48	UNITS (BBL)	6,513	7,143	(630)	(8.82)	6,513	7,143	(630)	(8.82)
49	UNIT COST ($/BBL)	110.49	117.59	(7.10)	(6.04)	110.49	117.59	(7.10)	(6.04)
50	AMOUNT ($)	719,623	839,922	(120,299)	(14.32)	719,623	839,922	(120,299)	(14.32)
51	DAYS SUPPLY	3	3	0	0.00				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2015

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) ¢ / KWH (a) FUEL COST	(6) ¢ / KWH (b) TOTAL COST	(7) (5) x (6)(a) TOTAL $ FOR FUEL ADJ.	(8) (5) x (6)(b) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		35,669,000	0	35,669,000	2.60	2.93	928,000	1,045,000
2	Various	Economy Sales	8,789,000	0	8,789,000	3.12	3.31	274,000	291,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	21,000	21,000
4	TOTAL ESTIMATED SALES		44,458,000	0	44,458,000	2.75	3.05	1,223,000	1,357,000
	ACTUAL								
5	Southern Company Interchange		22,881,973	0	22,881,973	2.28	2.48	522,312	567,916
6	A.E.C.	External	163,811	0	163,811	1.97	3.07	3,234	5,022
7	AECI	External	0	0	0	0.00	0.00	0	0
8	AEP	External	0	0	0	0.00	0.00	0	0
9	BAM	External	0	0	0	0.00	0.00	0	0
10	CALPINE	External	0	0	0	0.00	0.00	0	0
11	CARGILE	External	316,814	0	316,814	1.89	3.00	5,972	9,503
12	DUKE PWR	External	0	0	0	0.00	0.00	0	0
13	EAGLE EN	External	161,689	0	161,689	2.13	3.09	3,449	5,002
14	ENDURE	External	0	0	0	0.00	0.00	0	0
15	EU	External	12,535	0	12,535	1.56	2.43	195	305
16	EXELON	External	424,128	0	424,128	3.26	2.55	13,831	10,831
17	FPC	External	55,381	0	55,381	1.76	2.76	974	1,531
18	FPL	External	479,316	0	479,316	2.14	3.61	10,276	17,298
19	JPMVEC	External	55,709	0	55,709	1.81	2.96	1,009	1,648
20	MISO	External	171,708	0	171,708	1.85	2.85	3,181	4,885
21	MORGAN	External	223,830	0	223,830	1.61	2.11	3,609	4,724
22	NCEMC	External	0	0	0	0.00	0.00	(70)	0
23	NCMPA1	External	0	0	0	0.00	0.00	0	0
24	NOBLEAGP	External	0	0	0	0.00	0.00	0	0
25	NRG	External	0	0	0	0.00	0.00	0	0
26	OPC	External	16,912	0	16,912	1.96	2.96	332	500
27	ORLANDO	External	0	0	0	0.00	0.00	0	0
28	PJM	External	1,644,347	0	1,644,347	1.89	3.07	31,136	50,532
29	SCE&G	External	991,315	0	991,315	2.11	2.64	20,932	26,196
30	SEC	External	6,632	0	6,632	1.99	2.72	132	180
31	SEPA	External	119,243	0	119,243	1.99	3.00	2,377	3,578
32	SPP	External	0	0	0	0.00	0.00	0	0
33	TAL	External	21,554	0	21,554	2.70	4.27	582	920
34	TEA	External	853,624	0	853,624	2.18	3.12	18,567	26,613
35	TECO	External	115,133	0	115,133	2.31	3.57	2,661	4,111
36	TENASKA	External	0	0	0	0.00	0.00	0	0
37	TVA	External	107,110	0	107,110	1.89	2.91	2,021	3,119
38	WRI	External	574,529	0	574,529	1.62	2.26	9,317	12,979
39	Less: Flow-Thru Energy		(5,665,946)	0	(5,665,946)	1.94	1.94	(109,659)	(109,659)
40	SEPA		1,894,376	1,894,376	0	0.00	0.00	0	0
41	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	17,658	17,658
42	Other transactions including adj.		140,477,234	139,138,267	1,338,967	0.00	0.00	0	0
43	TOTAL ACTUAL SALES		166,102,957	141,032,643	25,070,314	0.34	0.39	564,029	647,734
44	Difference in Amount		121,644,957	141,032,643	(19,387,686)	(2.41)	(2.66)	(658,971)	(709,266)
45	Difference in Percent		273.62	0.00	(43.61)	(87.64)	(87.21)	(53.88)	(52.27)

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 41

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2015

				PERIOD TO DATE					
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
				KWH		(a)	(b)		
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	¢ / KWH FUEL COST	¢ / KWH TOTAL COST	TOTAL $ FOR FUEL ADJ.	TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		583,059,000	0	583,059,000	2.97	3.34	17,292,000	19,473,000
2	Various	Economy Sales	39,595,000	0	39,595,000	3.08	3.36	1,221,000	1,329,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	110,000	110,000
4	TOTAL ESTIMATED SALES		622,654,000	0	622,654,000	2.99	3.36	18,623,000	20,912,000
	ACTUAL								
5	Southern Company Interchange		724,774,235	0	724,774,235	2.90	3.16	20,995,006	22,896,234
6	A.E.C.	External	24,348,302	0	24,348,302	2.36	2.88	574,990	700,387
7	AECI	External	401,439	0	401,439	2.37	2.99	9,528	11,994
8	AEP	External	0	0	0	0.00	0.00	0	0
9	BAM	External	5,903	0	5,903	2.00	3.27	118	193
10	CALPINE	External	0	0	0	0.00	0.00	0	0
11	CARGILE	External	891,683	0	891,683	2.26	3.27	20,174	29,129
12	DUKE PWR	External	2,153,566	0	2,153,566	2.26	3.56	48,730	76,600
13	EAGLE EN	External	1,670,226	0	1,670,226	2.61	4.04	43,663	67,508
14	ENDURE	External	41,782	0	41,782	2.40	4.13	1,003	1,724
15	EU	External	12,535	0	12,535	1.56	2.43	195	305
16	EXELON	External	2,000,730	0	2,000,730	2.68	3.30	53,639	65,976
17	FPC	External	287,770	0	287,770	2.14	3.12	6,158	8,967
18	FPL	External	1,201,839	0	1,201,839	2.17	3.86	26,083	46,334
19	JPMVEC	External	750,553	0	750,553	2.43	3.12	18,220	23,432
20	MISO	External	2,001,043	0	2,001,043	1.97	3.09	39,409	61,886
21	MORGAN	External	3,180,108	0	3,180,108	2.13	2.87	67,714	91,196
22	NCEMC	External	1,306,951	0	1,306,951	2.30	3.23	30,081	42,196
23	NCMPA1	External	1,658	0	1,658	1.61	2.80	27	46
24	NOBLEAGP	External	26,528	0	26,528	1.59	2.80	422	743
25	NRG	External	0	0	0	0.00	0.00	0	0
26	OPC	External	473,733	0	473,733	2.58	3.79	12,239	17,973
27	ORLANDO	External	33,160	0	33,160	3.07	4.20	1,017	1,393
28	PJM	External	6,883,443	0	6,883,443	2.22	3.75	153,121	258,451
29	SCE&G	External	3,456,887	0	3,456,887	2.90	3.53	100,333	121,870
30	SEC	External	48,082	0	48,082	2.77	3.54	1,330	1,704
31	SEPA	External	2,885,672	0	2,885,672	2.05	3.13	59,019	90,338
32	SPP	External	0	0	0	0.00	0.00	0	0
33	TAL	External	181,064	0	181,064	1.99	3.80	3,611	6,882
34	TEA	External	8,930,351	0	8,930,351	2.12	3.24	189,325	289,005
35	TECO	External	723,634	0	723,634	2.20	3.42	15,910	24,732
36	TENASKA	External	7,627	0	7,627	2.82	3.20	215	244
37	TVA	External	3,016,187	0	3,016,187	2.30	3.86	69,401	116,388
38	WRI	External	1,570,257	0	1,570,257	1.97	2.67	30,866	41,981
39	Less: Flow-Thru Energy		(65,159,860)	0	(65,159,860)	2.25	2.25	(1,466,104)	(1,466,104)
40	SEPA		5,445,968	5,445,968	0	0.00	0.00	0	0
41	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	370,250	370,249
42	Other transactions including adj.		838,106,166	682,938,480	155,167,686	0.00	0.00	0	0
43	TOTAL ACTUAL SALES		1,571,659,222	688,384,448	883,274,774	1.37	1.50	21,475,690	23,629,704
44	Difference in Amount		949,005,222	688,384,448	260,620,774	(1.62)	(1.86)	2,852,690	2,717,704
45	Difference in Percent		152.41	0.00	41.86	(54.18)	(55.36)	15.32	13.00

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 41

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: APRIL 2015

(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: APRIL 2015

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.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	5,167,000	0	0	0	3.52	3.52	181,922
3	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
4	Ascend Performance Materials	COG 1	10,745,000	0	0	0	2.36	2.36	253,582
5	International Paper	COG 1	31,000	0	0	0	2.35	2.35	728
6	TOTAL		15,943,000	0	0	0	2.74	2.74	436,232

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.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	14,295,000	0	0	0	3.52	3.52	503,078
3	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	11
4	Ascend Performance Materials	COG 1	55,534,000	0	0	0	2.72	2.72	1,512,547
5	International Paper	COG 1	570,000	0	0	0	2.80	2.80	15,987
6	TOTAL		70,399,000	0	0	0	2.89	2.89	2,031,623

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2015

		CURRENT MONTH			PERIOD - TO - DATE		
	(1) PURCHASED FROM	(2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	(5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	109,927,000	3.40	3,741,000	459,344,000	3.37	15,472,000
2	Economy Energy	2,796,000	3.15	88,000	14,822,000	3.48	516,000
3	Other Purchases	22,072,000	8.91	1,967,000	817,165,000	3.80	31,085,000
4	TOTAL ESTIMATED PURCHASES	134,795,000	4.30	5,796,000	1,291,331,000	3.65	47,073,000
	ACTUAL						
5	Southern Company Interchange	229,171,538	2.43	5,568,686	706,101,502	2.58	18,191,763
6	Non-Associated Companies	47,860,743	0.86	410,072	193,280,400	1.05	2,022,447
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	101,088,000	4.12	4,161,028	949,887,000	3.00	28,477,379
9	Other Wheeled Energy	891,000	0.00	N/A	186,468,000	0.00	N/A
10	Other Transactions	108,312,526	0.01	10,028	501,283,128	0.01	70,157
11	Less: Flow-Thru Energy	(5,665,946)	2.17	(122,776)	(65,159,860)	2.48	(1,618,398)
12	TOTAL ACTUAL PURCHASES	481,657,861	2.08	10,027,038	2,471,860,170	1.91	47,143,348
13	Difference in Amount	346,862,861	(2.22)	4,231,038	1,180,529,170	(1.74)	70,348
14	Difference in Percent	257.33	(51.63)	73.00	91.42	(47.67)	0.15

2015 CAPACITY CONTRACTS
GULF POWER COMPANY

	Capacity Costs ($)	CONTRACT	TERM		January	February	March	April	May	June	July	August	September	October	November	December	YTD
A.	CONTRACT/COUNTERPARTY	TYPE	Start	End													
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0.0	0	0.0	0									0
2	Power Purchase Agreements & Other Confidential Agreements				7,387,528	7,392,119	7,387,234	7,395,118									29,561,999
				Total	7,387,528	7,392,119	7,387,234	7,395,118									29,561,999

	Capacity Costs (MW)				January	February	March	April	May	June	July	August	September	October	November	December	YTD
B.	CONTRACT/COUNTERPARTY	TYPE	Start	End													
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0.0	0	0.0	0									0
2	Power Purchase Agreements & Other Confidential Agreements				Varies	Varies	Varies	Varies									

Docket No. 160001-EI
2015 Final True-Up Filing
Exhibit CSB-1, Page 74 of 202

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 150001-EI

MONTHLY FUEL FILING

MAY 2015

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
MAY 2015

		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)	30,087,562	19,847,732	10,239,830	51.59	807,916,000	548,165,000	259,751,000	47.39	3.7241	3.6208	0.10	2.85
2	Hedging Settlement Costs (A2)	4,168,464	0	4,168,464	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	10,919	0	10,919	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	34,266,945	19,847,732	14,419,213	72.65	807,916,000	548,165,000	259,751,000	47.39	4.2414	3.6208	0.62	17.14
6	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
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	12,941,292	18,720,000	(5,778,708)	(30.87)	625,359,802	568,875,000	56,484,802	9.93	2.0694	3.2907	(1.22)	(37.11)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	595,660	0	595,660	100.00	20,228,000	0	20,228,000	100.00	2.9447	0.0000	2.94	0.00
12	TOTAL COST OF PURCHASED POWER	13,536,952	18,720,000	(5,183,048)	(27.69)	645,587,802	568,875,000	76,712,802	13.49	2.0968	3.2907	(1.19)	(36.28)
13	Total Available MWH (Line 5 + Line 12)	47,803,897	38,567,732	9,236,165	23.95	1,453,503,802	1,117,040,000	336,463,802	30.12				
14	Fuel Cost of Economy Sales (A6)	(133,919)	(303,000)	169,081	(55.80)	(4,750,822)	(9,617,000)	4,866,178	(50.60)	(2.8189)	(3.1507)	0.33	10.53
15	Gain on Economy Sales (A6)	(23,687)	(23,000)	(687)	2.99	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(6,099,278)	(2,001,000)	(4,098,278)	204.81	(397,044,026)	(67,209,000)	(329,835,026)	490.76	(1.5362)	(2.9773)	1.44	48.40
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(6,256,884)	(2,327,000)	(3,929,884)	168.88	(401,794,848)	(76,826,000)	(324,968,848)	422.99	(1.5572)	(3.0289)	1.47	48.59
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	41,547,013	36,240,732	5,306,281	14.64	1,051,708,954	1,040,214,000	11,494,954	1.11	3.9504	3.4840	0.47	13.39
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	77,961	56,963	20,998	36.86	1,973,488	1,635,000	338,488	20.70	3.9504	3.4840	0.47	13.39
22	T & D Losses *	1,777,717	2,051,205	(273,488)	(13.33)	45,000,935	58,875,000	(13,874,065)	(23.57)	3.9504	3.4840	0.47	13.39
23	TERRITORIAL KWH SALES	41,547,013	36,240,732	5,306,281	14.64	1,004,734,531	979,704,000	25,030,531	2.55	4.1351	3.6992	0.44	11.78
24	Wholesale KWH Sales	1,100,164	1,099,399	765	0.07	26,605,236	29,720,000	(3,114,764)	(10.48)	4.1351	3.6992	0.44	11.78
25	Jurisdictional KWH Sales	40,446,849	35,141,333	5,305,516	15.10	978,129,295	949,984,000	28,145,295	2.96	4.1351	3.6991	0.44	11.79
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	40,507,519	35,194,045	5,313,474	15.10	978,129,295	949,984,000	28,145,295	2.96	4.1413	3.7047	0.44	11.79
28	TRUE-UP	3,996,375	3,996,375	0	0.00	978,129,295	949,984,000	28,145,295	2.96	0.4086	0.4207	(0.01)	(2.88)
29	TOTAL JURISDICTIONAL FUEL COST	44,503,894	39,190,420	5,313,474	13.56	978,129,295	949,984,000	28,145,295	2.96	4.5499	4.1254	0.42	10.29
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.5532	4.1284	0.42	10.29
32	GPIF Reward / (Penalty)	210,328	210,328	0	0.00	978,129,295	949,984,000	28,145,295	2.96	0.0215	0.0221	(0.00)	(2.71)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.5747	4.1505	0.42	10.22
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.575	4.151		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: MAY 2015

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 30,087,562
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	10,919
4	Hedging Settlement Costs	Schedule A-2, Line A-5	4,168,464
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	12,941,292
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	595,660
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(6,256,884)
10	Total Fuel and Net Power Transactions		$ 41,547,013

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
MAY 2015
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)	119,777,828	127,651,798	(7,873,970)	(6.17)	3,379,768,000	3,290,465,000	89,303,000	2.71	3.5440	3.8794	(0.34)	(8.65)
2	Hedging Settlement Costs (A2)	18,331,894	0	18,331,894	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	(105,447)	0	(105,447)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	138,004,275	127,651,798	10,352,477	8.11	3,379,768,000	3,290,465,000	89,303,000	2.71	4.0832	3.8794	0.20	5.25
6	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
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0.00	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	60,084,639	65,793,000	(5,708,361)	(8.68)	3,097,219,972	1,860,206,000	1,237,013,972	66.50	1.9400	3.5369	(1.60)	(45.15)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	2,627,283	0	2,627,283	100.00	90,627,000	0	90,627,000	100.00	2.8990	0.0000	2.90	0.00
12	TOTAL COST OF PURCHASED POWER	62,711,922	65,793,000	(3,081,078)	(4.68)	3,187,846,972	1,860,206,000	1,327,640,972	71.37	1.9672	3.5369	(1.57)	(44.38)
13	Total Available MWH (Line 5 + Line 12)	200,716,197	193,444,798	7,271,399	3.76	6,567,614,972	5,150,671,000	1,416,943,972	27.51				
14	Fuel Cost of Economy Sales (A6)	(1,710,457)	(1,524,000)	(186,457)	12.23	(73,243,535)	(49,212,000)	(24,031,535)	48.83	(2.3353)	(3.0968)	0.76	24.59
15	Gain on Economy Sales (A6)	(393,937)	(133,000)	(260,937)	196.19	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(25,628,180)	(19,293,000)	(6,335,180)	32.84	(1,900,210,535)	(650,268,000)	(1,249,942,535)	192.22	(1.3487)	(2.9669)	1.62	54.54
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(27,732,573)	(20,950,000)	(6,782,573)	32.38	(1,973,454,070)	(699,480,000)	(1,273,974,070)	182.13	(1.4053)	(2.9951)	1.59	53.08
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	172,983,624	172,494,798	488,826	0.28	4,594,160,902	4,451,191,000	142,969,902	3.21	3.7653	3.8753	(0.11)	(2.84)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	352,629	340,767	11,862	3.48	9,365,217	8,793,300	571,917	6.50	3.7653	3.8753	(0.11)	(2.84)
22	T & D Losses *	8,165,157	8,537,856	(372,699)	(4.37)	216,852,772	220,314,700	(3,461,928)	(1.57)	3.7653	3.8753	(0.11)	(2.84)
23	TERRITORIAL KWH SALES	172,983,625	172,494,798	488,827	0.28	4,367,942,913	4,222,083,000	145,859,913	3.45	3.9603	4.0855	(0.13)	(3.06)
24	Wholesale KWH Sales	4,901,015	5,505,819	(604,804)	(10.98)	123,666,963	134,532,000	(10,865,037)	(8.08)	3.9631	4.0926	(0.13)	(3.16)
25	Jurisdictional KWH Sales	168,082,610	166,988,979	1,093,631	0.65	4,244,275,950	4,087,551,000	156,724,950	3.83	3.9602	4.0853	(0.13)	(3.06)
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	168,334,733	167,239,463	1,095,270	0.65	4,244,275,950	4,087,551,000	156,724,950	3.83	3.9662	4.0914	(0.13)	(3.06)
28	TRUE-UP	19,981,870	19,981,870	0	0.00	4,244,275,950	4,087,551,000	156,724,950	3.83	0.4708	0.4888	(0.02)	(3.68)
29	TOTAL JURISDICTIONAL FUEL COST	188,316,603	187,221,333	1,095,270	0.59	4,244,275,950	4,087,551,000	156,724,950	3.83	4.4370	4.5802	(0.14)	(3.13)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.4402	4.5835	(0.14)	(3.13)
32	GPIF Reward / (Penalty)	1,051,642	1,051,642	0	0.00	4,244,275,950	4,087,551,000	156,724,950	3.83	0.0248	0.0257	(0.00)	(3.50)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.4650	4.6092	(0.14)	(3.13)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.465	4.609		

* 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: MAY 2015

		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	29,828,928.11	19,535,197	10,293,731.11	52.69	118,643,362.47	126,531,893	(7,888,530.53)	(6.23)
1a	Other Generation	258,633.86	312,535	(53,901.14)	(17.25)	1,134,465.95	1,119,905	14,560.95	1.30
2	Fuel Cost of Power Sold	(6,256,884.59)	(2,327,000)	(3,929,884.59)	(168.88)	(27,732,574.40)	(20,950,000)	(6,782,574.40)	(32.38)
3	Fuel Cost - Purchased Power	12,941,292.51	18,720,000	(5,778,707.49)	(30.87)	60,084,639.30	65,793,000	(5,708,360.70)	(8.68)
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	595,659.62	0	595,659.62	100.00	2,627,283.31	0	2,627,283.31	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	4,168,464.43	0	4,168,464.43	100.00	18,331,894.43	0	18,331,894.43	100.00
6	Total Fuel & Net Power Transactions	41,536,093.94	36,240,732	5,295,361.94	14.61	173,089,071.06	172,494,798	594,273.06	0.34
7	AdjustmentsTo Fuel Cost*	10,919.25	0	10,919.25	100.00	(105,446.01)	0	(105,446.01)	100.00
8	Adj. Total Fuel & Net Power Transactions	41,547,013.19	36,240,732	5,306,281.19	14.64	172,983,625.05	172,494,798	488,827.05	0.28
B.	*KWH Sales*								
1	Jurisdictional Sales	978,129,295	949,984,000	28,145,295	2.96	4,244,275,950	4,087,551,000	156,724,950	3.83
2	Non-Jurisdictional Sales	26,605,236	29,720,000	(3,114,764)	(10.48)	123,666,963	134,532,000	(10,865,037)	(8.08)
3	Total Territorial Sales	1,004,734,531	979,704,000	25,030,531	2.55	4,367,942,913	4,222,083,000	145,859,913	3.45
4	Juris. Sales as % of Total Terr. Sales	97.3520	96.9664	0.3856	0.40	97.1688	96.8136	0.3552	0.37

**(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: MAY 2015

		CURRENT MONTH				PERIOD - TO - DATE			
		$		DIFFERENCE		$		DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	41,570,443.79	41,154,075	416,368.36	1.01	179,842,793.02	177,076,016	2,766,776.80	1.56
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(3,996,375.00)	3,996,375	(7,992,750.00)	(200.00)	(19,981,870.00)	19,981,870	(39,963,740.00)	(200.00)
2b	Incentive Provision	(210,177.00)	(210,177)	0.00	0.00	(1,050,883.00)	(1,050,883)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	37,363,891.79	44,940,273	(7,576,381.21)	(16.86)	158,810,040.02	196,007,003	(37,196,962.98)	(18.98)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	41,547,013.19	36,240,732	5,306,281.19	14.64	172,983,625.65	172,494,798	488,827.65	0.28
5	Juris. Sales % of Total KWH Sales (Line B4)	97.3520	96.9664	0.3856	0.40	97.1688	96.8136	0.3552	0.37
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	40,507,518.55	35,194,045	5,313,473.55	15.10	168,334,732.87	167,239,463	1,095,269.87	0.65
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(3,143,626.76)	9,746,228	(12,889,854.76)	132.25	(9,524,692.85)	28,767,539	(38,292,231.85)	133.11
8	Interest Provision for the Month	(2,000.53)	(2,818)	817.47	29.01	(12,905.15)	(16,948)	4,042.85	23.85
9	Beginning True-Up & Interest Provision	(30,285,088.39)	(44,934,809)	14,649,720.61	32.60	(39,871,741.42)	(47,956,495)	8,084,753.58	16.86
10	True-Up Collected / (Refunded)	3,996,375.00	(3,996,375)	7,992,750.00	(200.00)	19,981,870.00	(19,981,870)	39,963,740.00	(200.00)
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(29,434,340.68)	(39,187,774)	9,753,433.32	24.89	(29,427,469.42)	(39,187,774)	9,760,304.58	24.91
12	Adjustment		0	0.00	0.00	(6,871.26)	0	(6,871.26)	100.00
13	End of Period - Total Net True-Up	(29,434,340.68)	(39,187,774)	9,753,433.32	24.89	(29,434,340.68)	(39,187,774)	9,753,433.32	24.89

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2015

		CURRENT MONTH			
		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(30,285,088.39)	(44,934,809)	14,649,720.61	(32.60)
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	(29,432,340.15)	(39,184,956)	9,752,615.85	(24.89)
3	Total of Beginning & Ending True-Up Amts.	(59,717,428.54)	(84,119,765)	24,402,336.46	(29.01)
4	Average True-Up Amount	(29,858,714.27)	(42,059,883)	12,201,168.73	(29.01)
	Interest Rate				
5	1st Day of Reporting Business Month	0.06	0.06	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.10	0.10	0.0000	
7	Total (D5+D6)	0.16	0.16	0.0000	
8	Annual Average Interest Rate	0.08	0.08	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0067	0.0067	0.0000	
10	Interest Provision (D4*D9)	(2,000.53)	(2,818)	817.47	(29.01)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0015		

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2015

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	229,745	63,271	166,474	263.11	941,465	518,581	422,884	81.55
2	COAL	20,126,400	8,155,943	11,970,457	146.77	74,825,492	68,785,906	6,039,586	8.78
3	GAS	9,497,393	11,417,667	(1,920,274)	(16.82)	42,999,864	57,001,287	(14,001,423)	(24.56)
4	GAS (B.L.)	138,683	147,536	(8,853)	(6.00)	505,819	1,037,680	(531,861)	(51.25)
5	LANDFILL GAS	67,604	63,315	4,289	6.77	318,485	308,344	10,141	3.29
6	OIL - C.T.	27,737	0	27,737	100.00	186,702	0	186,702	100.00
7	TOTAL ($)	30,087,562	19,847,732	10,239,830	51.59	119,777,828	127,651,798	(7,873,970)	(6.17)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	490,488	224,173	266,315	118.80	1,794,613	1,732,985	61,628	3.56
10	GAS	315,137	321,892	(6,755)	(2.10)	1,574,102	1,547,253	26,849	1.74
11	LANDFILL GAS	2,148	2,100	48	2.29	10,427	10,227	200	1.96
12	OIL - C.T.	143	0	143	100.00	626	0	626	100.00
13	TOTAL (MWH)	807,916	548,165	259,751	47.39	3,379,768	3,290,465	89,303	2.71
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	2,693	511	2,182	427.01	10,607	4,156	6,451	155.22
15	COAL (TONS)	240,546	117,150	123,396	105.33	869,045	839,101	29,944	3.57
16	GAS (MCF) (1)	1,598,624	2,150,633	(552,009)	(25.67)	9,748,503	10,419,036	(670,533)	(6.44)
17	OIL - C.T. (BBL)	251	0	251	100.00	1,690	0	1,690	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	5,280,346	2,340,455	2,939,891	125.61	19,904,240	18,773,758	1,130,482	6.02
19	GAS - Generation (1)	1,630,111	2,150,633	(520,522)	(24.20)	9,920,803	10,419,036	(498,233)	(4.78)
20	OIL - C.T.	1,465	0	1,465	100.00	9,855	0	9,855	100.00
21	TOTAL (MMBTU)	6,911,922	4,491,088	2,420,834	53.90	29,834,898	29,192,794	642,104	2.20
	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	60.70	40.90	19.80	48.41	53.10	52.67	0.43	0.82
24	GAS	39.01	58.72	(19.71)	(33.57)	46.57	47.02	(0.45)	(0.96)
25	LANDFILL GAS	0.27	0.38	(0.11)	(28.95)	0.31	0.31	0.00	0.00
26	OIL - C.T.	0.02	0.00	0.02	100.00	0.02	0.00	0.02	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)	85.30	123.82	(38.52)	(31.11)	88.76	124.78	(36.02)	(28.87)
29	COAL ($/TON)	83.67	69.62	14.05	20.18	86.10	81.98	4.12	5.03
30	GAS ($/MCF) (1)	5.87	5.23	0.64	12.24	4.35	5.46	(1.11)	(20.33)
31	OIL - C.T. ($/BBL)	110.51	0.00	110.51	100.00	110.47	0.00	110.47	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	3.88	3.57	0.31	8.68	3.83	3.75	0.08	2.13
33	GAS - Generation (1)	5.67	5.16	0.51	9.88	4.22	5.36	(1.14)	(21.27)
34	OIL - C.T.	18.93	0.00	18.93	100.00	18.95	0.00	18.95	100.00
35	TOTAL ($/MMBTU)	4.31	4.34	(0.03)	(0.69)	3.97	4.32	(0.35)	(8.10)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	10,765	10,440	325	3.11	11,091	10,833	258	2.38
37	GAS - Generation (1)	5,301	6,864	(1,563)	(22.77)	6,433	6,870	(437)	(6.36)
38	OIL - C.T.	10,247	0	10,247	100.00	15,742	0	15,742	100.00
39	TOTAL (BTU/KWH)	8,660	8,356	304	3.64	8,939	8,984	(45)	(0.50)
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	4.18	3.73	0.45	12.06	4.25	4.06	0.19	4.68
41	GAS	3.01	3.55	(0.54)	(15.21)	2.73	3.68	(0.95)	(25.82)
42	LANDFILL GAS	3.15	3.02	0.13	4.30	3.05	3.01	0.04	1.33
43	OIL - C.T.	19.40	0.00	19.40	100.00	29.82	0.00	29.82	100.00
44	TOTAL (¢/KWH)	3.72	3.62	0.10	2.76	3.54	3.88	(0.34)	(8.76)

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: MAY 2015

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2015	(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	36,186	64.8	100.0	64.9	10,834	Coal	17,056	11,493	392,047	1,476,985	4.08	86.60
2				0					Gas-G	0	1,020	0	0	0.00	0.00
3									Gas-S	0	1,020	0	0		0.00
4									Oil-S	30	137,660	173	3,461		115.37
5	Crist 5		75	(1,050)	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
6				-					Gas-G	0	1,020	0	0	0.00	0.00
7									Gas-S	0	1,020	0	0		0.00
8									Oil-S	0	137,660	0	0		0.00
9	Crist 6		299	16,156	7.3	15.8	46.1	12,517	Coal	8,640	11,702	202,220	748,230	4.63	86.60
10				0					Gas-G	16,308	1,020	16,634	276,077	0.00	0.00
11									Gas-S	8,192	1,020	8,356	138,683		16.93
12									Oil-S	0	137,660	0	0		0.00
13	Crist 7		475	217,393	61.5	100.0	61.5	10,447	Coal	98,995	11,471	2,271,141	8,572,625	3.94	86.60
14				0					Gas-G	0	1,020	0	0	0.00	0.00
15									Gas-S	0	1,020	0	0		0.00
16									Oil-S	29	137,660	167	3,345		115.34
17	Scholz 1		46	(1)	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	0	0	0		0.00
19	Scholz 2		46	(1)	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	0	0	0		0.00
21	Smith 1		162	(957)	0.0	61.4	0.0	0	Coal	(1)	0	0	0	0.00	0.00
22									Oil-S	0	139,294	0	0		0.00
23	Smith 2		195	30,706	21.2	100.0	35.0	11,700	Coal	15,925	11,280	359,262	1,347,700	4.39	84.63
24									Oil-S	340	139,294	1,989	28,439		83.64
25	Smith 3		479	306,275	85.9	94.2	98.6	5,268	Gas-G	1,574,124	1,025	1,613,477	8,962,682	2.93	5.69
26	Smith A	(2)	32	143	0.6	86.7	72.7	10,245	Oil	251	138,971	1,465	27,737	19.40	110.51
27	Other Generation			7,634									258,634	3.39	0.00
28	Perdido			2,148					Landfill Gas				67,604	3.15	0.00
29	Daniel 1	(1)	255	106,074	55.9	99.4	56.0	10,394	Coal	53,307	10,342	1,102,570	4,213,334	3.97	79.04
30									Oil-S	1,575	138,968	9,194	133,536		84.78
31	Daniel 2	(1)	255	87,210	46.0	99.1	55.2	10,653	Coal	46,624	9,963	929,030	3,685,111	4.23	79.04
32									Oil-S	719	138,968	4,197	60,964		84.79
33	Total		2,394	807,916	45.4	78.4	55.4	8,660				6,911,922	30,005,147	3.71	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

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)	
	Coal Additive - Crist	86,436	
	Recoverable Fuel	30,087,562	3.72

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2015

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES :*								
2	UNITS (BBL)	3,707	511	3,196	625.44	10,320	4,156	6,164	148.32
3	UNIT COST ($/BBL)	85.36	122.25	(36.89)	(30.18)	78.55	122.71	(44.16)	(35.99)
4	AMOUNT ($)	316,423	62,470	253,953	406.52	810,662	509,978	300,684	58.96
5	*BURNED :*								
6	UNITS (BBL)	2,718	511	2,207	431.90	10,981	4,156	6,825	164.22
7	UNIT COST ($/BBL)	85.28	123.82	(38.54)	(31.13)	89.16	124.78	(35.62)	(28.55)
8	AMOUNT ($)	231,793	63,271	168,522	266.35	979,085	518,581	460,504	88.80
9	*ENDING INVENTORY :*								
10	UNITS (BBL)	6,335	7,166	(831)	(11.60)	6,335	7,166	(831)	(11.60)
11	UNIT COST ($/BBL)	102.38	125.60	(23.22)	(18.49)	102.38	125.60	(23.22)	(18.49)
12	AMOUNT ($)	648,561	900,074	(251,513)	(27.94)	648,561	900,074	(251,513)	(27.94)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES :*								
15	UNITS (TONS)	191,205	109,550	81,655	74.54	820,058	777,560	42,498	5.47
16	UNIT COST ($/TON)	86.69	77.41	9.28	11.99	87.03	78.63	8.40	10.68
17	AMOUNT ($)	16,576,238	8,480,566	8,095,672	95.46	71,369,769	61,137,772	10,231,997	16.74
18	*BURNED :*								
19	UNITS (TONS)	240,546	117,150	123,396	105.33	869,045	839,101	29,944	3.57
20	UNIT COST ($/TON)	83.33	69.62	13.71	19.69	86.02	81.98	4.04	4.93
21	AMOUNT ($)	20,043,985	8,155,943	11,888,042	145.76	74,759,165	68,785,906	5,973,259	8.68
22	*ENDING INVENTORY :*								
23	UNITS (TONS)	507,475	442,610	64,865	14.66	507,475	442,610	64,865	14.66
24	UNIT COST ($/TON)	82.83	77.58	5.25	6.77	82.83	77.58	5.25	6.77
25	AMOUNT ($)	42,035,978	34,335,582	7,700,396	22.43	42,035,978	34,335,582	7,700,396	22.43
26	DAYS SUPPLY	25	21	4	19.05				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES :*								
28	UNITS (MMBTU)	2,282,852	2,150,633	132,219	6.15	11,002,365	10,494,036	508,329	4.84
29	UNIT COST ($/MMBTU)	4.26	5.23	(0.97)	(18.55)	3.75	5.42	(1.67)	(30.81)
30	AMOUNT ($)	9,715,356	11,252,668	(1,537,312)	(13.66)	41,217,669	56,919,062	(15,701,393)	(27.59)
31	*BURNED :*								
32	UNITS (MMBTU)	2,259,675	2,150,633	109,042	5.07	11,251,034	10,494,036	756,998	7.21
33	UNIT COST ($/MMBTU)	4.15	5.23	(1.08)	(20.65)	3.77	5.42	(1.65)	(30.44)
34	AMOUNT ($)	9,376,692	11,252,668	(1,875,976)	(16.67)	42,367,467	56,919,062	(14,551,595)	(25.57)
35	*ENDING INVENTORY :*								
36	UNITS (MMBTU)	792,673	0	792,673	100.00	792,673	0	792,673	100.00
37	UNIT COST ($/MMBTU)	4.01	0.00	4.01	100.00	4.01	0.00	4.01	100.00
38	AMOUNT ($)	3,178,919	0	3,178,919	100.00	3,178,919	0	3,178,919	100.00
	OTHER - C.T. OIL								
39	*PURCHASES :*								
40	UNITS (BBL) *	0	0	0	0.00	894	0	894	100.00
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	68.86	0.00	69.00	100.00
42	AMOUNT ($)	0	0	0	0.00	61,561	0	61,561	100.00
43	*BURNED :*								
44	UNITS (BBL)	251	0	251	100.00	1,690	0	1,690	100.00
45	UNIT COST ($/BBL)	110.51	0.00	110.51	100.00	110.47	0.00	110.47	100.00
46	AMOUNT ($)	27,737	0	27,737	100.00	186,701	0	186,701	100.00
47	*ENDING INVENTORY :*								
48	UNITS (BBL)	6,262	7,143	(881)	(12.33)	6,262	7,143	(881)	(12.33)
49	UNIT COST ($/BBL)	110.49	117.59	(7.10)	(6.04)	110.49	117.59	(7.10)	(6.04)
50	AMOUNT ($)	691,886	839,922	(148,036)	(17.62)	691,886	839,922	(148,036)	(17.62)
51	DAYS SUPPLY	3	3	0	0.00				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2015

			CURRENT MONTH						
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
				KWH		(a)	(b)	(5) x (6)(a)	(5) x (6)(b)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	¢ / KWH FUEL COST	¢ / KWH TOTAL COST	TOTAL $ FOR FUEL ADJ.	TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		67,209,000	0	67,209,000	2.98	3.39	2,001,000	2,280,000
2	Various	Economy Sales	9,617,000	0	9,617,000	3.15	3.40	303,000	327,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	23,000	23,000
4	TOTAL ESTIMATED SALES		76,826,000	0	76,826,000	3.03	3.42	2,327,000	2,630,000
	ACTUAL								
5	Southern Company Interchange		224,211,912	0	224,211,912	2.77	3.05	6,206,734	6,841,450
6	A.E.C.	External	103,328	0	103,328	2.76	3.58	2,852	3,703
7	AECI	External	0	0	0	0.00	0.00	0	0
8	AEP	External	0	0	0	0.00	0.00	0	0
9	BAM	External	0	0	0	0.00	0.00	0	0
10	CALPINE	External	0	0	0	0.00	0.00	0	0
11	CARGILE	External	53,056	0	53,056	14.29	3.57	7,583	1,894
12	DUKE PWR	External	130,990	0	130,990	3.62	6.05	4,742	7,919
13	EAGLE EN	External	49,872	0	49,872	2.29	3.31	1,142	1,652
14	ENDURE	External	29,844	0	29,844	2.21	3.93	661	1,174
15	EU	External	0	0	0	0.00	0.00	0	0
16	EXELON	External	380,414	0	380,414	2.03	2.43	7,715	9,258
17	FPC	External	0	0	0	0.00	0.00	2	0
18	FPL	External	359,338	0	359,338	3.20	5.36	11,513	19,259
19	JPMVEC	External	72,621	0	72,621	1.99	2.68	1,447	1,946
20	MISO	External	88,607	0	88,607	2.50	3.28	2,216	2,908
21	MORGAN	External	47,750	0	47,750	20.19	3.58	9,641	1,709
22	NCEMC	External	43,637	0	43,637	2.93	3.79	1,280	1,652
23	NCMPA1	External	0	0	0	0.00	0.00	0	0
24	NOBLEAGP	External	0	0	0	0.00	0.00	0	0
25	NRG	External	0	0	0	0.00	0.00	0	0
26	OPC	External	321,998	0	321,998	2.18	3.49	7,034	11,224
27	ORLANDO	External	206,264	0	206,264	3.11	5.10	6,409	10,527
28	PJM	External	1,056,387	0	1,056,387	2.47	3.41	26,046	36,003
29	SCE&G	External	435,320	0	435,320	2.32	2.90	10,099	12,637
30	SEC	External	0	0	0	0.00	0.00	1	0
31	SEPA	External	301,498	0	301,498	1.91	2.87	5,773	8,639
32	SPP	External	0	0	0	0.00	0.00	0	0
33	TAL	External	21,885	0	21,885	2.24	3.65	490	800
34	TEA	External	715,869	0	715,869	2.49	3.35	17,858	24,005
35	TECO	External	12,602	0	12,602	1.98	3.18	249	401
36	TENASKA	External	12,999	0	12,999	2.39	3.48	310	453
37	TVA	External	254,681	0	254,681	2.99	4.86	7,604	12,383
38	WRI	External	51,862	0	51,862	2.41	3.58	1,250	1,855
39	Less: Flow-Thru Energy		(4,283,798)	0	(4,283,798)	2.51	2.51	(107,456)	(107,456)
40	SEPA		810,216	810,216	0	0.00	0.00	0	0
41	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	23,687	23,687
42	Other transactions including adj.		176,305,696	132,228,415	44,077,281	0.00	0.00	0	0
43	TOTAL ACTUAL SALES		401,794,848	133,038,631	268,756,217	1.56	1.72	6,256,884	6,905,994
44	Difference in Amount		324,968,848	133,038,631	191,930,217	(1.47)	(1.70)	3,929,884	4,275,994
45	Difference in Percent		422.99	0.00	249.82	(48.51)	(49.71)	168.88	162.59

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 41

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2015

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) ¢ / KWH (a) FUEL COST	(6) ¢ / KWH (b) TOTAL COST	(7) TOTAL $ FOR FUEL ADJ.	(8) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		650,268,000	0	650,268,000	2.97	3.35	19,293,000	21,753,000
2	Various	Economy Sales	49,212,000	0	49,212,000	3.10	3.37	1,524,000	1,656,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	133,000	133,000
4	TOTAL ESTIMATED SALES		699,480,000	0	699,480,000	3.00	3.37	20,950,000	23,542,000
	ACTUAL								
5	Southern Company Interchange		948,986,147	0	948,986,147	2.87	3.13	27,201,740	29,737,684
6	A.E.C.	External	24,451,630	0	24,451,630	2.36	2.88	577,842	704,090
7	AECI	External	401,439	0	401,439	2.37	2.99	9,528	11,994
8	AEP	External	0	0	0	0.00	0.00	0	0
9	BAM	External	5,903	0	5,903	2.00	3.27	118	193
10	CALPINE	External	0	0	0	0.00	0.00	0	0
11	CARGILE	External	944,739	0	944,739	2.94	3.28	27,757	31,022
12	DUKE PWR	External	2,284,556	0	2,284,556	2.34	3.70	53,473	84,519
13	EAGLE EN	External	1,720,098	0	1,720,098	2.60	4.02	44,805	69,160
14	ENDURE	External	71,626	0	71,626	2.32	4.05	1,664	2,898
15	EU	External	12,535	0	12,535	1.56	2.43	195	305
16	EXELON	External	2,381,144	0	2,381,144	2.58	3.16	61,354	75,233
17	FPC	External	287,770	0	287,770	2.14	3.12	6,160	8,967
18	FPL	External	1,561,177	0	1,561,177	2.41	4.20	37,597	65,593
19	JPMVEC	External	823,174	0	823,174	2.39	3.08	19,667	25,378
20	MISO	External	2,089,650	0	2,089,650	1.99	3.10	41,625	64,793
21	MORGAN	External	3,227,858	0	3,227,858	2.40	2.88	77,355	92,905
22	NCEMC	External	1,350,588	0	1,350,588	2.32	3.25	31,361	43,848
23	NCMPA1	External	1,658	0	1,658	1.61	2.80	27	46
24	NOBLEAGP	External	26,528	0	26,528	1.59	2.80	422	743
25	NRG	External	0	0	0	0.00	0.00	0	0
26	OPC	External	795,731	0	795,731	2.42	3.67	19,273	29,197
27	ORLANDO	External	239,424	0	239,424	3.10	4.98	7,427	11,920
28	PJM	External	7,939,830	0	7,939,830	2.26	3.71	179,166	294,453
29	SCE&G	External	3,892,207	0	3,892,207	2.84	3.46	110,433	134,507
30	SEC	External	48,082	0	48,082	2.77	3.54	1,331	1,704
31	SEPA	External	3,187,170	0	3,187,170	2.03	3.11	64,791	98,977
32	SPP	External	0	0	0	0.00	0.00	0	0
33	TAL	External	202,949	0	202,949	2.02	3.78	4,101	7,682
34	TEA	External	9,646,220	0	9,646,220	2.15	3.24	207,183	313,010
35	TECO	External	736,236	0	736,236	2.19	3.41	16,159	25,133
36	TENASKA	External	20,626	0	20,626	2.55	3.38	525	697
37	TVA	External	3,270,868	0	3,270,868	2.35	3.94	77,005	128,771
38	WRI	External	1,622,119	0	1,622,119	1.98	2.70	32,116	43,837
39	Less: Flow-Thru Energy		(69,443,658)	0	(69,443,658)	2.27	2.27	(1,573,560)	(1,573,560)
40	SEPA		6,256,184	6,256,184	0	0.00	0.00	0	0
41	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	393,937	393,937
42	Other transactions including adj.		1,014,411,862	815,166,895	199,244,967	0.00	0.00	0	0
43	TOTAL ACTUAL SALES		1,973,454,070	821,423,079	1,152,030,991	1.41	1.55	27,732,574	30,535,698
44	Difference in Amount		1,273,974,070	821,423,079	452,550,991	(1.59)	(1.82)	6,782,574	6,993,698
45	Difference in Percent		182.13	0.00	64.70	(53.00)	(54.01)	32.38	29.71

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 41

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: MAY 2015

(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: MAY 2015

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.
ESTIMATED								
1		0	0	0	0	0.00	0.00	0
ACTUAL								
2 Bay County/Engen, LLC	Contract	4,057,000	0	0	0	3.66	3.66	148,536
3 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
4 Ascend Performance Materials	COG 1	16,113,000	0	0	0	2.76	2.76	445,446
5 International Paper	COG 1	58,000	0	0	0	2.89	2.89	1,678
6 TOTAL		20,228,000	0	0	0	2.94	2.94	595,660

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.
ESTIMATED								
1		0	0	0	0	0.00	0.00	0
ACTUAL								
2 Bay County/Engen, LLC	Contract	18,352,000	0	0	0	3.55	3.55	651,614
3 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	11
4 Ascend Performance Materials	COG 1	71,647,000	0	0	0	2.73	2.73	1,957,993
5 International Paper	COG 1	628,000	0	0	0	2.81	2.81	17,665
6 TOTAL		90,627,000	0	0	0	2.90	2.90	2,627,283

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2015

		CURRENT MONTH			PERIOD - TO - DATE		
	(1) PURCHASED FROM	(2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	(5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	92,181,000	3.16	2,912,000	551,525,000	3.33	18,384,000
2	Economy Energy	3,472,000	3.43	119,000	18,294,000	3.47	635,000
3	Other Purchases	473,222,000	3.32	15,689,000	1,290,387,000	3.62	46,774,000
4	TOTAL ESTIMATED PURCHASES	568,875,000	3.29	18,720,000	1,860,206,000	3.54	65,793,000
	ACTUAL						
5	Southern Company Interchange	60,514,988	2.35	1,419,874	766,616,490	2.56	19,611,636
6	Non-Associated Companies	69,227,563	1.22	846,756	262,507,963	1.09	2,869,203
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	366,911,000	2.94	10,782,603	1,316,798,000	2.98	39,259,982
9	Other Wheeled Energy	58,225,000	0.00	N/A	244,693,000	0.00	N/A
10	Other Transactions	74,765,049	0.01	9,799	576,048,177	0.01	79,956
11	Less: Flow-Thru Energy	(4,283,798)	2.75	(117,740)	(69,443,658)	2.50	(1,736,138)
12	TOTAL ACTUAL PURCHASES	625,359,802	2.07	12,941,292	3,097,219,972	1.94	60,084,639
13	Difference in Amount	56,484,802	(1.22)	(5,778,708)	1,237,013,972	(1.60)	(5,708,361)
14	Difference in Percent	9.93	(37.08)	(30.87)	66.50	(45.20)	(8.68)

SCHEDULE A-12

2015 CAPACITY CONTRACTS
GULF POWER COMPANY

	Capacity Costs ($)	CONTRACT	TERM		January	February	March	April	May	June	July	August	September	October	November	December	YTD
A.	CONTRACT/COUNTERPARTY	TYPE	Start	End													
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0	0	0	0	0								0
2	Power Purchase Agreements & Other Confidential Agreements				7,387,528	7,392,119	7,387,234	7,395,118	7,397,373								36,959,372
				Total	7,387,528	7,392,119	7,387,234	7,395,118	7,397,373								36,959,372

	Capacity Costs (MW)				January	February	March	April	May	June	July	August	September	October	November	December	YTD
B.	CONTRACT/COUNTERPARTY	TYPE	Start	End													
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0	0	0	0	0								0
2	Power Purchase Agreements & Other Confidential Agreements				Varies	Varies	Varies	Varies	Varies								

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 150001-EI

MONTHLY FUEL FILING

JUNE 2015

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JUNE 2015

		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)	31,847,640	24,460,069	7,387,571	30.20	845,127,000	670,075,000	175,052,000	26.12	3.7684	3.6503	0.12	3.24
2	Hedging Settlement Costs (A2)	4,097,270	0	4,097,270	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	212	0	212	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	35,945,122	24,460,069	11,485,053	46.95	845,127,000	670,075,000	175,052,000	26.12	4.2532	3.6503	0.60	16.52
6	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
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	13,707,133	20,368,000	(6,660,867)	(32.70)	695,497,775	602,939,000	92,558,775	15.35	1.9708	3.3781	(1.41)	(41.66)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	476,940	0	476,940	100.00	15,799,000	0	15,799,000	100.00	3.0188	0.0000	3.02	0.00
12	TOTAL COST OF PURCHASED POWER	14,184,073	20,368,000	(6,183,927)	(30.36)	711,296,775	602,939,000	108,357,775	17.97	1.9941	3.3781	(1.38)	(40.97)
13	Total Available MWH (Line 5 + Line 12)	50,129,195	44,828,069	5,301,126	11.83	1,556,423,775	1,273,014,000	283,409,775	22.26				
14	Fuel Cost of Economy Sales (A6)	(117,909)	(251,000)	133,091	(53.02)	(4,909,825)	(6,905,000)	1,995,175	(28.89)	(2.4015)	(3.6350)	1.23	33.93
15	Gain on Economy Sales (A6)	(24,402)	(43,000)	18,598	(43.25)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(5,192,767)	(2,261,000)	(2,931,767)	129.67	(368,354,396)	(57,476,000)	(310,878,396)	540.88	(1.4097)	(3.9338)	2.52	64.16
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(5,335,078)	(2,555,000)	(2,780,078)	108.81	(373,264,221)	(64,381,000)	(308,883,221)	479.77	(1.4293)	(3.9686)	2.54	63.98
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	44,794,117	42,273,069	2,521,048	5.96	1,183,159,554	1,208,633,000	(25,473,446)	(2.11)	3.7860	3.4976	0.29	8.25
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	74,693	61,278	13,415	21.89	1,972,875	1,752,000	220,875	12.61	3.7860	3.4976	0.29	8.25
22	T & D Losses *	1,747,885	2,744,287	(996,402)	(36.31)	46,167,072	78,462,000	(32,294,928)	(41.16)	3.7860	3.4976	0.29	8.25
23	TERRITORIAL KWH SALES	44,794,117	42,273,069	2,521,048	5.96	1,135,019,607	1,128,419,000	6,600,607	0.58	3.9466	3.7462	0.20	5.35
24	Wholesale KWH Sales	1,174,905	1,231,373	(56,468)	(4.59)	29,770,105	32,870,000	(3,099,895)	(9.43)	3.9466	3.7462	0.20	5.35
25	Jurisdictional KWH Sales	43,619,212	41,041,696	2,577,516	6.28	1,105,249,502	1,095,549,000	9,700,502	0.89	3.9465	3.7462	0.20	5.35
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	43,684,641	41,103,259	2,581,382	6.28	1,105,249,502	1,095,549,000	9,700,502	0.89	3.9525	3.7518	0.20	5.35
28	TRUE-UP	3,996,375	3,996,375	0	0.00	1,105,249,502	1,095,549,000	9,700,502	0.89	0.3616	0.3648	(0.00)	(0.88)
29	TOTAL JURISDICTIONAL FUEL COST	47,681,016	45,099,634	2,581,382	5.72	1,105,249,502	1,095,549,000	9,700,502	0.89	4.3141	4.1166	0.20	4.80
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.3172	4.1196	0.20	4.80
32	GPIF Reward / (Penalty)	210,328	210,328	0	0.00	1,105,249,502	1,095,549,000	9,700,502	0.89	0.0190	0.0192	(0.00)	(1.04)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.3362	4.1388	0.20	4.77
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.336	4.139		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: JUNE 2015

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 31,847,640
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	212
4	Hedging Settlement Costs	Schedule A-2, Line A-5	4,097,270
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	13,707,133
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	476,940
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(5,335,078)
10	Total Fuel and Net Power Transactions		$ 44,794,117

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JUNE 2015
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)	151,625,468	152,111,867	(486,399)	(0.32)	4,224,895,000	3,960,540,000	264,355,000	6.67	3.5889	3.8407	(0.25)	(6.56)
2	Hedging Settlement Costs (A2)	22,429,164	0	22,429,164	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	(105,234)	0	(105,234)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	173,949,398	152,111,867	21,837,531	14.36	4,224,895,000	3,960,540,000	264,355,000	6.67	4.1172	3.8407	0.28	7.20
6	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
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0.00	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	73,791,772	86,161,000	(12,369,228)	(14.36)	3,792,717,747	2,463,145,000	1,329,572,747	53.98	1.9456	3.4980	(1.55)	(44.38)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	3,104,223	0	3,104,223	100.00	106,426,000	0	106,426,000	100.00	2.9168	0.0000	2.92	0.00
12	TOTAL COST OF PURCHASED POWER	76,895,995	86,161,000	(9,265,005)	(10.75)	3,899,143,747	2,463,145,000	1,435,998,747	58.30	1.9721	3.4980	(1.53)	(43.62)
13	Total Available MWH (Line 5 + Line 12)	250,845,393	238,272,867	12,572,526	5.28	8,124,038,747	6,423,685,000	1,700,353,747	26.47				
14	Fuel Cost of Economy Sales (A6)	(1,828,365)	(1,775,000)	(53,365)	3.01	(78,153,360)	(56,117,000)	(22,036,360)	39.27	(2.3395)	(3.1630)	0.82	26.04
15	Gain on Economy Sales (A6)	(418,339)	(176,000)	(242,339)	137.69	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(30,820,947)	(21,554,000)	(9,266,947)	42.99	(2,268,564,931)	(707,744,000)	(1,560,820,931)	220.53	(1.3586)	(3.0455)	1.69	55.39
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(33,067,652)	(23,505,000)	(9,562,651)	40.68	(2,346,718,291)	(763,861,000)	(1,582,857,291)	207.22	(1.4091)	(3.0771)	1.67	54.21
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	217,777,741	214,767,867	3,009,874	1.40	5,777,320,456	5,659,824,000	117,496,456	2.08	3.7695	3.7946	(0.03)	(0.66)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	427,389	400,152	27,237	6.81	11,338,092	10,545,300	792,792	7.52	3.7695	3.7946	(0.03)	(0.66)
22	T & D Losses *	9,914,533	11,337,381	(1,422,848)	(12.55)	263,019,844	298,776,700	(35,756,856)	(11.97)	3.7695	3.7946	(0.03)	(0.66)
23	TERRITORIAL KWH SALES	217,777,742	214,767,867	3,009,875	1.40	5,502,962,520	5,350,502,000	152,460,520	2.85	3.9575	4.0140	(0.06)	(1.41)
24	Wholesale KWH Sales	6,075,920	6,737,192	(661,272)	(9.82)	153,437,068	167,402,000	(13,964,932)	(8.34)	3.9599	4.0246	(0.06)	(1.61)
25	Jurisdictional KWH Sales	211,701,822	208,030,675	3,671,147	1.76	5,349,525,452	5,183,100,000	166,425,452	3.21	3.9574	4.0136	(0.06)	(1.40)
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	212,019,374	208,342,722	3,676,652	1.76	5,349,525,452	5,183,100,000	166,425,452	3.21	3.9633	4.0197	(0.06)	(1.40)
28	TRUE-UP	23,978,245	23,978,245	0	0.00	5,349,525,452	5,183,100,000	166,425,452	3.21	0.4482	0.4626	(0.01)	(3.11)
29	TOTAL JURISDICTIONAL FUEL COST	235,997,619	232,320,967	3,676,652	1.58	5,349,525,452	5,183,100,000	166,425,452	3.21	4.4115	4.4823	(0.07)	(1.58)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.4147	4.4855	(0.07)	(1.58)
32	GPIF Reward / (Penalty)	1,261,970	1,261,970	0	0.00	5,349,525,452	5,183,100,000	166,425,452	3.21	0.0236	0.0243	(0.00)	(2.88)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.4383	4.5098	(0.07)	(1.59)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.438	4.510		

* 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: JUNE 2015

		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	31,621,134.55	24,157,597	7,463,537.55	30.90	150,264,497.02	150,689,490	(424,992.98)	(0.28)
1a	Other Generation	226,505.10	302,472	(75,966.90)	(25.12)	1,360,971.05	1,422,377	(61,405.95)	(4.32)
2	Fuel Cost of Power Sold	(5,335,077.99)	(2,555,000)	(2,780,077.99)	(108.81)	(33,067,652.39)	(23,505,000)	(9,562,652.39)	(40.68)
3	Fuel Cost - Purchased Power	13,707,132.79	20,368,000	(6,660,867.21)	(32.70)	73,791,772.09	86,161,000	(12,369,227.91)	(14.36)
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	476,940.45	0	476,940.45	100.00	3,104,223.76	0	3,104,223.76	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	4,097,270.00	0	4,097,270.00	100.00	22,429,164.43	0	22,429,164.43	100.00
6	Total Fuel & Net Power Transactions	44,793,904.90	42,273,069	2,520,835.90	5.96	217,882,975.96	214,767,867	3,115,108.96	1.45
7	AdjustmentsTo Fuel Cost*	212.19	0	212.19	100.00	(105,233.82)	0	(105,233.82)	100.00
8	Adj. Total Fuel & Net Power Transactions	44,794,117.09	42,273,069	2,521,048.09	5.96	217,777,742.14	214,767,867	3,009,875.14	1.40
B.	*KWH Sales*								
1	Jurisdictional Sales	1,105,249,502	1,095,549,000	9,700,502	0.89	5,349,525,452	5,183,100,000	166,425,452	3.21
2	Non-Jurisdictional Sales	29,770,105	32,870,000	(3,099,895)	(9.43)	153,437,068	167,402,000	(13,964,932)	(8.34)
3	Total Territorial Sales	1,135,019,607	1,128,419,000	6,600,607	0.58	5,502,962,520	5,350,502,000	152,460,520	2.85
4	Juris. Sales as % of Total Terr. Sales	97.3771	97.0871	0.2900	0.30	97.2117	96.8713	0.3404	0.35

**(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: JUNE 2015

C.	*True-up Calculation*	CURRENT MONTH $ ACTUAL	$ ESTIMATED	DIFFERENCE $ AMOUNT ($)	DIFFERENCE %	PERIOD - TO - DATE $ ACTUAL	$ ESTIMATED	DIFFERENCE $ AMOUNT ($)	DIFFERENCE %
1	Jurisdictional Fuel Revenue	49,016,438.69	47,460,069	1,556,369.69	3.28	228,859,231.71	224,536,085	4,323,146.49	1.93
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(3,996,375.00)	(3,996,375)	0.00	0.00	(23,978,245.00)	(23,978,245)	0.00	0.00
2b	Incentive Provision	(210,177.00)	(210,177)	0.00	0.00	(1,261,060.00)	(1,261,060)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	44,809,886.69	43,253,517	1,556,369.69	3.60	203,619,926.71	199,296,780	4,323,146.71	2.17
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	44,794,117.09	42,273,069	2,521,048.09	5.96	217,777,742.74	214,767,867	3,009,875.74	1.40
5	Juris. Sales % of Total KWH Sales (Line B4)	97.3771	97.0871	0.2900	0.30	97.2117	96.8713	0.3404	0.35
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	43,684,641.01	41,103,259	2,581,382.01	6.28	212,019,373.88	208,342,722	3,676,651.88	1.76
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	1,125,245.68	2,150,258	(1,025,012.32)	47.67	(8,399,447.17)	30,917,797	(39,317,244.17)	127.17
8	Interest Provision for the Month	(2,015.51)	(2,709)	693.49	25.60	(14,920.66)	(19,657)	4,736.34	24.09
9	Beginning True-Up & Interest Provision	(29,434,340.68)	(39,187,774)	9,753,433.32	24.89	(39,871,741.42)	(47,956,495)	8,084,753.58	16.86
10	True-Up Collected / (Refunded)	3,996,375.00	3,996,375	0.00	0.00	23,978,245.00	(15,985,495)	39,963,740.00	(250.00)
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(24,314,735.51)	(33,043,850)	8,729,114.49	26.42	(24,307,864.25)	(33,043,850)	8,735,985.75	26.44
12	Adjustment		0	0.00	0.00	(6,871.26)	0	(6,871.26)	100.00
13	End of Period - Total Net True-Up	(24,314,735.51)	(33,043,850)	8,729,114.49	26.42	(24,314,735.51)	(33,043,850)	8,729,114.49	26.42

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2015

		CURRENT MONTH			
		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(29,434,340.68)	(39,187,774)	9,753,433.32	(24.89)
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(24,312,720.00)	(33,041,141)	8,728,421.00	(26.42)
3	Total of Beginning & Ending True-Up Amts.	(53,747,060.68)	(72,228,915)	18,481,854.32	(25.59)
4	Average True-Up Amount	(26,873,530.34)	(36,114,458)	9,240,927.66	(25.59)
	Interest Rate				
5	1st Day of Reporting Business Month	0.10	0.10	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.08	0.08	0.0000	
7	Total (D5+D6)	0.18	0.18	0.0000	
8	Annual Average Interest Rate	0.09	0.09	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0075	0.0075	0.0000	
10	Interest Provision (D4*D9)	(2,015.51)	(2,709)	693.49	(25.60)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0015		

Docket No. 160001-EI
2015 Final True-Up Filing
Exhibit CSB-1, Page 97 of 202

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2015

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	250,958	70,337	180,621	256.79	1,192,423	588,918	603,505	102.48
2	COAL	22,237,473	12,215,780	10,021,693	82.04	97,062,964	81,001,686	16,061,278	19.83
3	GAS	9,064,174	11,914,609	(2,850,435)	(23.92)	52,064,038	68,915,896	(16,851,858)	(24.45)
4	GAS (B.L.)	196,439	167,536	28,903	17.25	702,259	1,205,216	(502,957)	(41.73)
5	LANDFILL GAS	61,179	91,807	(30,628)	(33.36)	379,665	400,151	(20,486)	(5.12)
6	OIL - C.T.	37,416	0	37,416	100.00	224,118	0	224,118	100.00
7	TOTAL ($)	31,847,640	24,460,069	7,387,570	30.20	151,625,468	152,111,867	(486,399)	(0.32)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	550,535	328,397	222,138	67.64	2,345,148	2,061,382	283,766	13.77
10	GAS	292,492	338,633	(46,141)	(13.63)	1,866,594	1,885,886	(19,292)	(1.02)
11	LANDFILL GAS	1,985	3,045	(1,060)	(34.81)	12,412	13,272	(860)	(6.48)
12	OIL - C.T.	115	0	115	100.00	741	0	741	100.00
13	TOTAL (MWH)	845,127	670,075	175,052	26.12	4,224,895	3,960,540	264,355	6.67
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	2,546	567	1,979	349.03	13,153	4,723	8,430	178.49
15	COAL (TONS)	266,821	163,403	103,418	63.29	1,135,866	1,002,504	133,362	13.30
16	GAS (MCF) (1)	2,083,556	2,270,734	(187,178)	(8.24)	11,832,059	12,689,770	(857,711)	(6.76)
17	OIL - C.T. (BBL)	349	0	349	100.00	2,039	0	2,039	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	5,993,412	3,420,333	2,573,079	75.23	25,897,652	22,194,091	3,703,561	16.69
19	GAS - Generation (1)	2,128,185	2,270,734	(142,549)	(6.28)	12,048,988	12,689,770	(640,782)	(5.05)
20	OIL - C.T.	2,028	0	2,028	100.00	11,883	0	11,883	100.00
21	TOTAL (MMBTU)	8,123,625	5,691,067	2,432,558	42.74	37,958,523	34,883,861	3,074,662	8.81
	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	65.15	49.01	16.14	32.93	55.51	52.04	3.47	6.67
24	GAS	34.61	50.54	(15.93)	(31.52)	44.18	47.62	(3.44)	(7.22)
25	LANDFILL GAS	0.23	0.45	(0.22)	(48.89)	0.29	0.34	(0.05)	(14.71)
26	OIL - C.T.	0.01	0.00	0.01	100.00	0.02	0.00	0.02	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)	98.57	124.05	(25.48)	(20.54)	90.66	124.69	(34.03)	(27.29)
29	COAL ($/TON)	83.34	74.76	8.58	11.48	85.45	80.80	4.65	5.75
30	GAS ($/MCF) (1)	4.34	5.19	(0.85)	(16.38)	4.34	5.41	(1.07)	(19.78)
31	OIL - C.T. ($/BBL)	107.21	0.00	107.21	100.00	109.92	0.00	109.92	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	3.78	3.64	0.14	3.85	3.82	3.73	0.09	2.41
33	GAS - Generation (1)	4.15	5.11	(0.96)	(18.79)	4.21	5.32	(1.11)	(20.86)
34	OIL - C.T.	18.45	0.00	18.45	100.00	18.86	0.00	18.86	100.00
35	TOTAL ($/MMBTU)	3.88	4.23	(0.35)	(8.27)	3.95	4.31	(0.36)	(8.35)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	10,887	10,415	472	4.53	11,043	10,767	276	2.56
37	GAS - Generation (1)	7,436	6,874	562	8.18	6,590	6,871	(281)	(4.09)
38	OIL - C.T.	17,637	0	17,637	100.00	16,036	0	16,036	100.00
39	TOTAL (BTU/KWH)	9,708	8,639	1,069	12.37	9,093	8,926	167	1.87
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	4.12	3.79	0.33	8.71	4.22	4.02	0.20	4.98
41	GAS	3.10	3.52	(0.42)	(11.93)	2.79	3.65	(0.86)	(23.56)
42	LANDFILL GAS	3.08	3.02	0.06	1.99	3.06	3.02	0.04	1.32
43	OIL - C.T.	32.54	0.00	32.54	100.00	30.25	0.00	30.25	100.00
44	TOTAL (¢/KWH)	3.77	3.65	0.12	3.29	3.59	3.84	(0.25)	(6.51)

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: JUNE 2015

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2015	(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	29,340	54.3	100.0	63.2	11,183	Coal	14,206	11,548	328,110	1,220,912	4.16	85.94
2				0					Gas-G	192	1,021	196	7,195	0.00	37.47
3									Gas-S	0	1,021	0	0		0.00
4									Oil-S	372	138,131	2,156	42,945		115.44
5	Crist 5		75	(1,188)	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
6				-					Gas-G	0	1,021	0	0	0.00	0.00
7									Gas-S	0	1,021	0	0		0.00
8									Oil-S	0	138,131	0	0		0.00
9	Crist 6		299	86,107	40.0	99.4	62.5	10,863	Coal	40,318	11,600	935,369	3,464,950	4.02	85.94
10				0					Gas-G	2,858	1,021	2,918	107,122	0.00	0.00
11									Gas-S	5,241	1,021	5,351	196,439		37.48
12									Oil-S	798	138,131	4,632	92,289		115.65
13	Crist 7		475	218,091	63.8	98.7	64.1	10,757	Coal	101,257	11,584	2,345,899	8,702,076	3.99	85.94
14				0					Gas-G	0	1,021	0	0	0.00	0.00
15									Gas-S	0	1,021	0	0		0.00
16									Oil-S	50	138,131	293	5,828		116.56
17	Scholz 1		46	0	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	0	0	0		0.00
19	Scholz 2		46	0	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	0	0	0		0.00
21	Smith 1		162	27,571	23.6	100.0	41.5	0	Coal	(1)	11,191	0	0	0.00	0.00
22									Oil-S	240	138,385	1,394	19,971		83.21
23	Smith 2		195	(717)	0.0	100.0	0.0	0	Coal	14,242	11,191	318,768	1,189,159	0.00	83.50
24									Oil-S	0	138,385	0	0		0.00
25	Smith 3		479	285,900	82.9	90.5	97.8	7,433	Gas-G	2,075,265	1,024	2,125,071	8,723,352	3.05	4.20
26	Smith A	(2)	32	115	0.5	93.9	71.9	17,635	Oil	349	138,219	2,028	37,416	32.54	107.21
27	Other Generation			6,306									226,505	3.59	0.00
28	Perdido			1,985					Landfill Gas				61,179	3.08	0.00
29	Daniel 1	(1)	255	91,312	49.7	91.5	54.0	10,706	Coal	45,048	10,850	977,551	3,566,851	3.91	79.18
30									Oil-S	787	138,935	4,593	65,190		82.83
31	Daniel 2	(1)	255	100,305	54.6	98.3	55.6	10,643	Coal	51,751	10,314	1,067,553	4,097,547	4.09	79.18
32									Oil-S	299	138,935	1,743	24,735		82.73
33	Total		2,394	845,127	49.0	89.6	57.5	9,708				8,123,625	31,851,661	3.77	

Notes & Adjust.: (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

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)	
	Recoverable Fuel	31,847,640	3.77

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2015

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES :*								
2	UNITS (BBL)	1,231	567	664	117.11	11,551	4,723	6,828	144.57
3	UNIT COST ($/BBL)	79.28	122.54	(43.26)	(35.30)	78.63	122.69	(44.06)	(35.91)
4	AMOUNT ($)	97,595	69,478	28,117	40.47	908,257	579,456	328,801	56.74
5	*BURNED :*								
6	UNITS (BBL)	2,568	567	2,001	352.91	13,549	4,723	8,826	186.87
7	UNIT COST ($/BBL)	98.45	124.05	(25.60)	(20.64)	90.92	124.69	(33.77)	(27.08)
8	AMOUNT ($)	252,814	70,337	182,477	259.43	1,231,899	588,918	642,981	109.18
9	*ENDING INVENTORY :*								
10	UNITS (BBL)	4,998	7,166	(2,168)	(30.25)	4,998	7,166	(2,168)	(30.25)
11	UNIT COST ($/BBL)	98.71	125.48	(26.77)	(21.33)	98.71	125.48	(26.77)	(21.33)
12	AMOUNT ($)	493,342	899,215	(405,873)	(45.14)	493,342	899,215	(405,873)	(45.14)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES :*								
15	UNITS (TONS)	197,345	150,404	46,941	31.21	1,017,403	927,964	89,439	9.64
16	UNIT COST ($/TON)	82.20	77.50	4.70	6.06	86.09	78.45	7.64	9.74
17	AMOUNT ($)	16,221,063	11,656,748	4,564,315	39.16	87,590,832	72,794,520	14,796,312	20.33
18	*BURNED :*								
19	UNITS (TONS)	266,821	163,403	103,418	63.29	1,135,866	1,002,504	133,362	13.30
20	UNIT COST ($/TON)	83.38	74.76	8.62	11.53	85.40	80.80	4.60	5.69
21	AMOUNT ($)	22,248,509	12,215,780	10,032,729	82.13	97,007,674	81,001,686	16,005,988	19.76
22	*ENDING INVENTORY :*								
23	UNITS (TONS)	438,000	429,611	8,389	1.95	438,000	429,611	8,389	1.95
24	UNIT COST ($/TON)	82.21	78.62	3.59	4.57	82.21	78.62	3.59	4.57
25	AMOUNT ($)	36,008,532	33,776,550	2,231,982	6.61	36,008,532	33,776,550	2,231,982	6.61
26	DAYS SUPPLY	21	21	0	0.00				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES :*								
28	UNITS (MMBTU)	2,071,638	2,275,734	(204,096)	(8.97)	13,074,003	12,769,770	304,233	2.38
29	UNIT COST ($/MMBTU)	4.27	5.18	(0.91)	(17.57)	3.83	5.38	(1.55)	(28.81)
30	AMOUNT ($)	8,853,991	11,779,673	(2,925,682)	(24.84)	50,071,660	68,698,735	(18,627,075)	(27.11)
31	*BURNED :*								
32	UNITS (MMBTU)	2,133,536	2,275,734	(142,198)	(6.25)	13,384,570	12,769,770	614,800	4.81
33	UNIT COST ($/MMBTU)	4.23	5.18	(0.95)	(18.34)	3.84	5.38	(1.54)	(28.62)
34	AMOUNT ($)	9,033,358	11,779,673	(2,746,315)	(23.31)	51,400,825	68,698,735	(17,297,910)	(25.18)
35	*ENDING INVENTORY :*								
36	UNITS (MMBTU)	730,775	0	730,775	100.00	730,775	0	730,775	100.00
37	UNIT COST ($/MMBTU)	4.10	0.00	4.10	100.00	4.10	0.00	4.10	100.00
38	AMOUNT ($)	2,999,551	0	2,999,551	100.00	2,999,551	0	2,999,551	100.00
	OTHER - C.T. OIL								
39	*PURCHASES :*								
40	UNITS (BBL) *	883	0	883	100.00	1,777	0	1,777	100.00
41	UNIT COST ($/BBL)	83.02	0.00	83.02	100.00	75.90	0.00	76.00	100.00
42	AMOUNT ($)	73,306	0	73,306	100.00	134,867	0	134,867	100.00
43	*BURNED :*								
44	UNITS (BBL)	349	0	349	100.00	2,039	0	2,039	100.00
45	UNIT COST ($/BBL)	107.21	0.00	107.21	100.00	109.92	0.00	109.92	100.00
46	AMOUNT ($)	37,416	0	37,416	100.00	224,117	0	224,117	100.00
47	*ENDING INVENTORY :*								
48	UNITS (BBL)	6,796	7,143	(347)	(4.86)	6,796	7,143	(347)	(4.86)
49	UNIT COST ($/BBL)	107.09	117.59	(10.50)	(8.93)	107.09	117.59	(10.50)	(8.93)
50	AMOUNT ($)	727,776	839,922	(112,146)	(13.35)	727,776	839,922	(112,146)	(13.35)
51	DAYS SUPPLY	3	3	0	0.00				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2015

			CURRENT MONTH							
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
				KWH		(a)	(b)	(5) x (6)(a)	(5) x (6)(b)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	¢ / KWH FUEL COST	¢ / KWH TOTAL COST	TOTAL $ FOR FUEL ADJ.	TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		57,476,000	0	57,476,000	3.93	4.21	2,261,000	2,422,000
2	Various	Economy Sales	6,905,000	0	6,905,000	3.64	3.82	251,000	264,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	43,000	43,000
4	TOTAL ESTIMATED SALES		64,381,000	0	64,381,000	3.97	4.24	2,555,000	2,729,000
	ACTUAL								
5	Southern Company Interchange		177,704,609	0	177,704,609	2.98	3.23	5,294,519	5,747,642
6	A.E.C.	External	280,207	0	280,207	2.70	3.46	7,565	9,683
7	AECI	External	0	0	0	0.00	0.00	0	0
8	AEP	External	0	0	0	0.00	0.00	0	0
9	BAM	External	0	0	0	0.00	0.00	0	0
10	CALPINE	External	0	0	0	0.00	0.00	0	0
11	CARGILE	External	168,585	0	168,585	3.29	2.44	5,542	4,109
12	DUKE PWR	External	119,382	0	119,382	3.62	18.50	4,324	22,086
13	EAGLE EN	External	293,072	0	293,072	2.01	2.55	5,895	7,486
14	ENDURE	External	3,316	0	3,316	2.66	4.00	88	133
15	EU	External	0	0	0	0.00	0.00	0	0
16	EXELON	External	172,174	0	172,174	2.16	3.01	3,722	5,190
17	FPC	External	26,860	0	26,860	2.68	4.10	721	1,101
18	FPL	External	148,429	0	148,429	2.92	4.10	4,327	6,087
19	JPMVEC	External	9,617	0	9,617	3.71	5.32	357	512
20	MISO	External	53,056	0	53,056	2.86	2.81	1,519	1,489
21	MORGAN	External	71,626	0	71,626	2.09	2.37	1,499	1,698
22	NCEMC	External	37,472	0	37,472	3.16	3.95	1,184	1,482
23	NCMPA1	External	0	0	0	0.00	0.00	0	0
24	NOBLEAGP	External	0	0	0	0.00	0.00	0	0
25	NRG	External	0	0	0	0.00	0.00	0	0
26	OPC	External	10,611	0	10,611	3.58	6.20	380	658
27	ORLANDO	External	118,056	0	118,056	3.14	4.37	3,709	5,153
28	PJM	External	227,225	0	227,225	2.60	3.71	5,911	8,439
29	SCE&G	External	450,668	0	450,668	3.03	3.65	13,671	16,469
30	SEC	External	9,285	0	9,285	2.13	2.81	197	261
31	SEPA	External	1,489,737	0	1,489,737	1.93	2.80	28,762	41,783
32	SPP	External	0	0	0	0.00	0.00	0	0
33	TAL	External	3,316	0	3,316	1.83	2.65	61	88
34	TEA	External	979,897	0	979,897	2.43	3.30	23,764	32,335
35	TECO	External	101,339	0	101,339	1.91	2.95	1,938	2,992
36	TENASKA	External	0	0	0	0.00	0.00	0	0
37	TVA	External	9,286	0	9,286	3.68		341	353
38	WRI	External	126,609	0	126,609	1.92	2.40	2,432	3,034
39	Less: Flow-Thru Energy		(4,446,621)	0	(4,446,621)	2.29	2.29	(101,752)	(101,752)
40	SEPA		848,936	848,936	0	0.00	0.00	0	0
41	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	24,402	24,402
42	Other transactions including adj.		194,247,472	149,673,720	44,573,752	0.00	0.00	0	0
43	TOTAL ACTUAL SALES		373,264,221	150,522,656	222,741,565	1.43	1.56	5,335,078	5,818,510
44	Difference in Amount		308,883,221	150,522,656	158,360,565	(2.54)	(2.68)	2,780,078	3,089,510
45	Difference in Percent		479.77	0.00	245.97	(63.98)	(63.21)	108.81	113.21

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 41

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2015

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		707,744,000	0	707,744,000	3.05	3.42	21,554,000	24,175,000
2	Various	Economy Sales	56,117,000	0	56,117,000	3.16	3.42	1,775,000	1,920,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	176,000	176,000
4	TOTAL ESTIMATED SALES		763,861,000	0	763,861,000	3.08	3.44	23,505,000	26,271,000
	ACTUAL								
5	Southern Company Interchange		1,126,690,756	0	1,126,690,756	2.88	3.15	32,496,259	35,485,326
6	A.E.C.	External	24,731,837	0	24,731,837	2.37	2.89	585,407	713,773
7	AECI	External	401,439	0	401,439	2.37	2.99	9,528	11,994
8	AEP	External	0	0	0	0.00	0.00	0	0
9	BAM	External	5,903	0	5,903	2.00	3.27	118	193
10	CALPINE	External	0	0	0	0.00	0.00	0	0
11	CARGILE	External	1,113,324	0	1,113,324	2.99	3.16	33,299	35,132
12	DUKE PWR	External	2,403,938	0	2,403,938	2.40	4.43	57,797	106,604
13	EAGLE EN	External	2,013,170	0	2,013,170	2.52	3.81	50,700	76,646
14	ENDURE	External	74,942	0	74,942	2.34	4.04	1,752	3,030
15	EU	External	12,535	0	12,535	1.56	2.43	195	305
16	EXELON	External	2,553,318	0	2,553,318	2.55	3.15	65,076	80,424
17	FPC	External	314,630	0	314,630	2.19	3.20	6,881	10,068
18	FPL	External	1,709,606	0	1,709,606	2.45	4.19	41,924	71,680
19	JPMVEC	External	832,791	0	832,791	2.40	3.11	20,023	25,889
20	MISO	External	2,142,706	0	2,142,706	2.01	3.09	43,144	66,282
21	MORGAN	External	3,299,484	0	3,299,484	2.39	2.87	78,855	94,603
22	NCEMC	External	1,388,060	0	1,388,060	2.34	3.27	32,545	45,330
23	NCMPA1	External	1,658	0	1,658	1.61	2.80	27	46
24	NOBLEAGP	External	26,528	0	26,528	1.59	2.80	422	743
25	NRG	External	0	0	0	0.00	0.00	0	0
26	OPC	External	806,342	0	806,342	2.44	3.70	19,653	29,855
27	ORLANDO	External	357,480	0	357,480	3.11	4.78	11,136	17,073
28	PJM	External	8,167,055	0	8,167,055	2.27	3.71	185,077	302,892
29	SCE&G	External	4,342,875	0	4,342,875	2.86	3.48	124,104	150,976
30	SEC	External	57,367	0	57,367	2.66	3.43	1,528	1,965
31	SEPA	External	4,676,907	0	4,676,907	2.00	3.01	93,553	140,760
32	SPP	External	0	0	0	0.00	0.00	0	0
33	TAL	External	206,265	0	206,265	2.02	3.77	4,162	7,769
34	TEA	External	10,626,117	0	10,626,117	2.17	3.25	230,947	345,344
35	TECO	External	837,575	0	837,575	2.16	3.36	18,097	28,125
36	TENASKA	External	20,626	0	20,626	2.55	3.38	525	697
37	TVA	External	3,280,154	0	3,280,154	2.36	3.94	77,346	129,124
38	WRI	External	1,748,728	0	1,748,728	1.98	2.68	34,548	46,870
39	Less: Flow-Thru Energy		(73,890,279)	0	(73,890,279)	2.27	2.27	(1,675,312)	(1,675,312)
40	SEPA		7,105,120	7,105,120	0	0.00	0.00	0	0
41	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	418,339	418,339
42	Other transactions including adj.		1,208,659,334	964,840,615	243,818,719	0.00	0.00	0	0
43	TOTAL ACTUAL SALES		2,346,718,291	971,945,735	1,374,772,556	1.41	1.55	33,067,652	36,354,208
44	Difference in Amount		1,582,857,291	971,945,735	610,911,556	(1.67)	(1.89)	9,562,652	10,083,208
45	Difference in Percent		207.22	0.00	79.98	(54.22)	(54.94)	40.68	38.38

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 41

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: JUNE 2015

(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: JUNE 2015

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.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	5,498,000	0	0	0	3.52	3.52	193,428
3	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	41
4	Ascend Performance Materials	COG 1	10,236,000	0	0	0	2.75	2.75	281,667
5	International Paper	COG 1	65,000	0	0	0	2.78	2.78	1,804
6	TOTAL		15,799,000	0	0	0	3.02	3.02	476,940

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.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	23,850,000	0	0	0	3.54	3.54	845,042
3	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	52
4	Ascend Performance Materials	COG 1	81,883,000	0	0	0	2.74	2.74	2,239,660
5	International Paper	COG 1	693,000	0	0	0	2.81	2.81	19,469
6	TOTAL		106,426,000	0	0	0	2.92	2.92	3,104,223

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2015

	(1)	CURRENT MONTH			PERIOD - TO - DATE		
	PURCHASED FROM	(2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	(5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	134,826,000	3.33	4,490,000	686,351,000	3.33	22,874,000
2	Economy Energy	3,044,000	4.11	125,000	21,338,000	3.56	760,000
3	Other Purchases	465,069,000	3.39	15,753,000	1,755,456,000	3.56	62,527,000
4	TOTAL ESTIMATED PURCHASES	602,939,000	3.38	20,368,000	2,463,145,000	3.50	86,161,000
	ACTUAL						
5	Southern Company Interchange	98,891,365	2.34	2,312,451	865,507,855	2.53	21,924,087
6	Non-Associated Companies	73,122,624	0.95	694,872	335,630,587	1.06	3,564,075
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	384,729,000	2.81	10,804,789	1,701,527,000	2.94	50,064,771
9	Other Wheeled Energy	69,846,000	0.00	N/A	314,539,000	0.00	N/A
10	Other Transactions	73,355,407	0.01	6,384	649,403,584	0.01	86,340
11	Less: Flow-Thru Energy	(4,446,621)	2.50	(111,363)	(73,890,279)	2.50	(1,847,501)
12	TOTAL ACTUAL PURCHASES	695,497,775	1.97	13,707,133	3,792,717,747	1.95	73,791,772
13	Difference in Amount	92,558,775	(1.41)	(6,660,867)	1,329,572,747	(1.55)	(12,369,228)
14	Difference in Percent	15.35	(41.72)	(32.70)	53.98	(44.29)	(14.36)

SCHEDULE A-12

2015 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	0	0	0							0
2	Power Purchase Agreements & Other Confidential Agreements				7,387,528	7,392,119	7,387,234	7,395,118	7,397,373	7,423,168							44,382,540
				Total	7,387,528	7,392,119	7,387,234	7,395,118	7,397,373	7,423,168							44,382,540

Capacity Costs (MW)

B.	CONTRACT/COUNTERPARTY	TYPE	Start	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	0	0	0							0
2	Power Purchase Agreements & Other Confidential Agreements				Varies	Varies	Varies	Varies	Varies	Varies							

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 150001-EI

MONTHLY FUEL FILING

JULY 2015

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JULY 2015

		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)	35,371,512	30,298,922	5,072,590	16.74	976,633,000	881,410,000	95,223,000	10.80	3.6218	3.4376	0.18	5.36
2	Hedging Settlement Costs (A2)	4,129,455	4,209,240	(79,785)	(1.90)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	1,369	0	1,369	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	39,502,336	34,508,162	4,994,174	14.47	976,633,000	881,410,000	95,223,000	10.80	4.0447	3.9151	0.13	3.31
6	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
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	15,604,543.96	15,186,000	418,544	2.76	770,279,250	613,413,000	156,866,250	25.57	2.0258	2.4757	(0.45)	(18.17)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	352,279	0	352,279	100.00	11,267,000	0	11,267,000	100.00	3.1266	0.0000	3.13	0.00
12	TOTAL COST OF PURCHASED POWER	15,956,823	15,186,000	770,823	5.08	781,546,250	613,413,000	168,133,250	27.41	2.0417	2.4757	(0.43)	(17.53)
13	Total Available MWH (Line 5 + Line 12)	55,459,159	49,694,162	5,764,997	11.60	1,758,179,250	1,494,823,000	263,356,250	17.62				
14	Fuel Cost of Economy Sales (A6)	(175,868)	(187,000)	11,132	(5.95)	(6,857,303)	(6,403,000)	(454,303)	7.10	(2.5647)	(2.9205)	0.36	12.18
15	Gain on Economy Sales (A6)	(82,970)	(88,000)	5,030	(5.72)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(6,565,643)	(6,196,000)	(369,643)	5.97	(426,821,813)	(204,353,000)	(222,468,813)	108.86	(1.5383)	(3.0320)	1.49	49.26
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(6,824,481)	(6,471,000)	(353,481)	5.46	(433,679,116)	(210,756,000)	(222,923,116)	105.77	(1.5736)	(3.0704)	1.50	48.75
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	48,634,678	43,223,162	5,411,516	12.52	1,324,500,134	1,284,067,000	40,433,134	3.15	3.6719	3.3661	0.31	9.08
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	77,260	58,200	19,060	32.75	2,104,100	1,729,000	375,100	21.69	3.6719	3.3661	0.31	9.08
22	T & D Losses *	2,200,406	2,712,875	(512,469)	(18.89)	59,925,556	80,594,000	(20,668,444)	(25.65)	3.6719	3.3661	0.31	9.08
23	TERRITORIAL KWH SALES	48,634,678	43,223,162	5,411,516	12.52	1,262,470,478	1,201,744,000	60,726,478	5.05	3.8523	3.5967	0.26	7.11
24	Wholesale KWH Sales	1,274,520	1,179,516	95,004	8.05	33,084,608	32,794,000	290,608	0.89	3.8523	3.5967	0.26	7.11
25	Jurisdictional KWH Sales	47,360,158	42,043,646	5,316,512	12.65	1,229,385,870	1,168,950,000	60,435,870	5.17	3.8523	3.5967	0.26	7.11
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	47,431,198	42,106,711	5,324,487	12.65	1,229,385,870	1,168,950,000	60,435,870	5.17	3.8581	3.6021	0.26	7.11
28	TRUE-UP	3,996,375	3,996,375	0	0.00	1,229,385,870	1,168,950,000	60,435,870	5.17	0.3251	0.3419	(0.02)	(4.91)
29	TOTAL JURISDICTIONAL FUEL COST	51,427,573	46,103,086	5,324,487	11.55	1,229,385,870	1,168,950,000	60,435,870	5.17	4.1832	3.9440	0.24	6.06
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.1862	3.9468	0.24	6.07
32	GPIF Reward / (Penalty)	210,328	210,328	0	0.00	1,229,385,870	1,168,950,000	60,435,870	5.17	0.0171	0.0180	(0.00)	(5.00)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.2033	3.9648	0.24	6.02
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.203	3.965		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: JULY 2015

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 35,371,512
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	1,369
4	Hedging Settlement Costs	Schedule A-2, Line A-5	4,129,455
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	15,604,544
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	352,279
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(6,824,482)
10	Total Fuel and Net Power Transactions		$ 48,634,677

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
JULY 2015
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)	186,996,980	182,410,789	4,586,191	2.51	5,201,528,000	4,841,950,000	359,578,000	7.43	3.5950	3.7673	(0.17)	(4.57)
2	Hedging Settlement Costs (A2)	26,558,619	4,209,240	22,349,379	530.96	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	(103,865)	0	(103,865)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	213,451,734	186,620,029	26,831,705	14.38	5,201,528,000	4,841,950,000	359,578,000	7.43	4.1036	3.8542	0.25	6.47
6	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
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0.00	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	89,396,317	101,347,000	(11,950,683)	(11.79)	4,562,996,997	3,076,558,000	1,486,438,997	48.31	1.9592	3.2942	(1.34)	(40.53)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	3,456,503	0	3,456,503	100.00	117,693,000	0	117,693,000	100.00	2.9369	0.0000	2.94	0.00
12	TOTAL COST OF PURCHASED POWER	92,852,820	101,347,000	(8,494,180)	(8.38)	4,680,689,997	3,076,558,000	1,604,131,997	52.14	1.9837	3.2942	(1.31)	(39.78)
13	Total Available MWH (Line 5 + Line 12)	306,304,554	287,967,029	18,337,525	6.37	9,882,217,997	7,918,508,000	1,963,709,997	24.80				
14	Fuel Cost of Economy Sales (A6)	(2,004,234)	(1,962,000)	(42,234)	2.15	(85,010,663)	(62,520,000)	(22,490,663)	35.97	(2.3576)	(3.1382)	0.78	24.87
15	Gain on Economy Sales (A6)	(501,309)	(264,000)	(237,309)	89.89	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(37,386,590)	(27,750,000)	(9,636,590)	34.73	(2,695,386,744)	(912,097,000)	(1,783,289,744)	195.52	(1.3871)	(3.0424)	1.66	54.41
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(39,892,133.50)	(29,976,000)	(9,916,132)	33.08	(2,780,397,407)	(974,617,000)	(1,805,780,407)	185.28	(1.4348)	(3.0757)	1.64	53.35
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	266,412,420	257,991,029	8,421,391	3.26	7,101,820,590	6,943,891,000	157,929,590	2.27	3.7513	3.7154	0.04	0.97
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	504,257	456,039	48,218	10.57	13,442,192	12,274,300	1,167,892	9.51	3.7513	3.7154	0.04	0.97
22	T & D Losses *	12,114,651	14,095,139	(1,980,488)	(14.05)	322,945,400	379,370,700	(56,425,300)	(14.87)	3.7513	3.7154	0.04	0.97
23	TERRITORIAL KWH SALES	266,412,420	257,991,029	8,421,391	3.26	6,765,432,998	6,552,246,000	213,186,998	3.25	3.9378	3.9374	0.00	0.01
24	Wholesale KWH Sales	7,350,440	7,916,708	(566,268)	(7.15)	186,521,676	200,196,000	(13,674,324)	(6.83)	3.9408	3.9545	(0.01)	(0.35)
25	Jurisdictional KWH Sales	259,061,980	250,074,321	8,987,659	3.59	6,578,911,322	6,352,050,000	226,861,322	3.57	3.9378	3.9369	0.00	0.02
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	259,450,572	250,449,433	9,001,139	3.59	6,578,911,322	6,352,050,000	226,861,322	3.57	3.9437	3.9428	0.00	0.02
28	TRUE-UP	27,974,620	27,974,620	0	0.00	6,578,911,322	6,352,050,000	226,861,322	3.57	0.4252	0.4404	(0.02)	(3.45)
29	TOTAL JURISDICTIONAL FUEL COST	287,425,192	278,424,053	9,001,139	3.23	6,578,911,322	6,352,050,000	226,861,322	3.57	4.3689	4.3832	(0.01)	(0.33)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.3720	4.3864	(0.01)	(0.33)
32	GPIF Reward / (Penalty)	1,472,298	1,472,298	0	0.00	6,578,911,322	6,352,050,000	226,861,322	3.57	0.0224	0.0232	(0.00)	(3.45)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.3944	4.4096	(0.02)	(0.34)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.394	4.410		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation

Docket No. 160001-EI
2015 Final True-Up Filing
Exhibit CSB-1, Page 110 of 202

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2015

		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	35,148,612.73	29,993,159	5,155,453.73	17.19	185,413,109.75	180,682,649	4,730,460.75	2.62
1a	Other Generation	222,899.09	305,763	(82,863.91)	(27.10)	1,583,870.14	1,728,140	(144,269.86)	(8.35)
2	Fuel Cost of Power Sold	(6,824,481.49)	(6,471,000)	(353,481.49)	(5.46)	(39,892,133.88)	(29,976,000)	(9,916,133.88)	(33.08)
3	Fuel Cost - Purchased Power	15,604,544.41	15,186,000	418,544.41	2.76	89,396,316.50	101,347,000	(11,950,683.50)	(11.79)
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	352,279.33	0	352,279.33	100.00	3,456,503.09	0	3,456,503.09	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	4,129,455.00	4,209,240	(79,785.00)	(1.90)	26,558,619.43	4,209,240	22,349,379.43	530.96
6	Total Fuel & Net Power Transactions	48,633,309.07	43,223,162	5,410,147.07	12.52	266,516,285.03	257,991,029	8,525,256.03	3.30
7	AdjustmentsTo Fuel Cost*	1,369.00	0	1,369.00	100.00	(103,864.82)	0	(103,864.82)	100.00
8	Adj. Total Fuel & Net Power Transactions	48,634,678.07	43,223,162	5,411,516.07	12.52	266,412,420.21	257,991,029	8,421,391.21	3.26
B.	*KWH Sales*								
1	Jurisdictional Sales	1,229,385,870	1,168,950,000	60,435,870	5.17	6,578,911,322	6,352,050,000	226,861,322	3.57
2	Non-Jurisdictional Sales	33,084,608	32,794,000	290,608	0.89	186,521,676	200,196,000	(13,674,324)	(6.83)
3	Total Territorial Sales	1,262,470,478	1,201,744,000	60,726,478	5.05	6,765,432,998	6,552,246,000	213,186,998	3.25
4	Juris. Sales as % of Total Terr. Sales	97.3794	97.2711	0.1083	0.11	97.2430	96.9446	0.2984	0.31

**(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: JULY 2015

		CURRENT MONTH				PERIOD - TO - DATE			
		$		DIFFERENCE		$		DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	54,775,822.61	50,639,860	4,135,962.91	8.17	283,635,054.32	275,175,945	8,459,109.40	3.07
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(3,996,375.00)	(3,996,375)	0.00	0.00	(27,974,620.00)	(27,974,620)	0.00	0.00
2b	Incentive Provision	(210,177.00)	(210,177)	0.00	0.00	(1,471,237.00)	(1,471,237)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	50,569,270.61	46,433,308	4,135,962.61	8.91	254,189,197.32	245,730,088	8,459,109.32	3.44
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	48,634,678.07	43,223,162	5,411,516.07	12.52	266,412,420.81	257,991,029	8,421,391.81	3.26
5	Juris. Sales % of Total KWH Sales (Line B4)	97.3794	97.2711	0.1083	0.11	97.2430	96.9446	0.2984	0.31
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	47,431,197.93	42,106,711	5,324,486.93	12.65	259,450,571.81	250,449,433	9,001,138.81	3.59
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	3,138,072.68	4,326,597	(1,188,524.32)	27.47	(5,261,374.49)	35,244,394	(40,505,768.49)	114.93
8	Interest Provision for the Month	(1,639.05)	(2,282)	642.95	28.17	(16,559.71)	(21,939)	5,379.29	24.52
9	Beginning True-Up & Interest Provision	(24,314,735.51)	(33,043,850)	8,729,114.49	26.42	(39,871,741.42)	(47,956,495)	8,084,753.58	16.86
10	True-Up Collected / (Refunded)	3,996,375.00	3,996,375	0.00	0.00	27,974,620.00	(11,989,120)	39,963,740.00	(333.33)
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(17,181,926.88)	(24,723,160)	7,541,233.12	30.50	(17,175,055.62)	(24,723,160)	7,548,104.38	30.53
12	Adjustment		0	0.00	0.00	(6,871.26)	0	(6,871.26)	100.00
13	End of Period - Total Net True-Up	(17,181,926.88)	(24,723,160)	7,541,233.12	30.50	(17,181,926.88)	(24,723,160)	7,541,233.12	30.50

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2015

		CURRENT MONTH			
		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(24,314,735.51)	(33,043,850)	8,729,114.49	(26.42)
2	Ending True-Up Amount Before Interest (C7+C9+C10)	(17,180,287.83)	(24,720,878)	7,540,590.17	(30.50)
3	Total of Beginning & Ending True-Up Amts.	(41,495,023.34)	(57,764,728)	16,269,704.66	(28.17)
4	Average True-Up Amount	(20,747,511.67)	(28,882,364)	8,134,852.33	(28.17)
5	Interest Rate 1st Day of Reporting Business Month	0.08	0.08	0.0000	
6	Interest Rate 1st Day of Subsequent Business Month	0.11	0.11	0.0000	
7	Total (D5+D6)	0.19	0.19	0.0000	
8	Annual Average Interest Rate	0.10	0.10	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0079	0.0079	0.0000	
10	Interest Provision (D4*D9)	(1,639.05)	(2,282)	642.95	(28.17)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0015		

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2015

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	60,228	84,046.00	(23,818)	(28.34)	1,252,651	672,964	579,687	86.14
2	COAL	24,718,799	19,225,965.00	5,492,834	28.57	121,781,764	100,227,651	21,554,113	21.51
3	GAS	10,212,713	10,639,350.00	(426,637)	(4.01)	62,276,751	79,555,246	(17,278,495)	(21.72)
4	GAS (B.L.)	313,288	285,322.00	27,966	9.80	1,015,547	1,490,538	(474,991)	(31.87)
5	LANDFILL GAS	66,483	64,239.00	2,244	3.49	446,147	464,390	(18,243)	(3.93)
6	OIL - C.T.	-	0	0	0.00	224,118	0	224,118	100.00
7	TOTAL ($)	35,371,512	30,298,922	5,072,590	16.74	186,996,980	182,410,789	4,586,191	2.51
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	632,798	513,753	119,045	23.17	2,977,946	2,575,135	402,811	15.64
10	GAS	341,698	365,557	(23,859)	(6.53)	2,208,292	2,251,443	(43,151)	(1.92)
11	LANDFILL GAS	2,146	2,100	46	2.19	14,558	15,372	(814)	(5.30)
12	OIL - C.T.	(9)	0	(9)	100.00	732	0	732	100.00
13	TOTAL (MWH)	976,633	881,410	95,223	10.80	5,201,528	4,841,950	359,578	7.43
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	663	940	(278)	(29.57)	13,816	5,663	8,153	143.97
15	COAL (TONS)	306,604	237,673	68,931	29.00	1,442,470	1,240,177	202,293	16.31
16	GAS (MCF) (1)	2,423,703	2,540,642	(116,939)	(4.60)	14,255,762	15,230,412	(974,650)	(6.40)
17	OIL - C.T. (BBL)	-	0	0	0.00	2,039	0	2,039	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	6,824,361	5,370,822	1,453,539	27.06	32,722,013	27,564,913	5,157,100	18.71
19	GAS - Generation (1)	2,476,861	2,571,455	(94,594)	(3.68)	14,525,849	15,261,225	(735,376)	(4.82)
20	OIL - C.T.	0	0	0	0.00	11,883	0	11,883	100.00
21	TOTAL (MMBTU)	9,301,222	7,942,277	1,358,945	17.11	47,259,745	42,826,138	4,433,607	10.35
	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	64.79	58.29	6.50	11.15	57.26	53.18	4.08	7.67
24	GAS	34.99	41.47	(6.48)	(15.63)	42.45	46.50	(4.05)	(8.71)
25	LANDFILL GAS	0.22	0.24	(0.02)	(8.33)	0.28	0.32	(0.04)	(12.50)
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)	90.91	89.41	1.50	1.68	90.67	118.84	(28.17)	(23.70)
29	COAL ($/TON)	80.62	80.89	(0.27)	(0.33)	84.43	80.82	3.61	4.47
30	GAS ($/MCF) (1)	4.25	4.18	0.07	1.67	4.33	5.21	(0.88)	(16.89)
31	OIL - C.T. ($/BBL)	0.00	0.00	0.00	0.00	109.92	0.00	109.92	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	3.68	3.65	0.03	0.82	3.79	3.71	0.08	2.16
33	GAS - Generation (1)	4.03	4.02	0.01	0.25	4.18	5.10	(0.92)	(18.04)
34	OIL - C.T.	0.00	0.00	0.00	0.00	18.86	0.00	18.86	100.00
35	TOTAL ($/MMBTU)	3.77	3.77	0.00	0.00	3.91	4.21	(0.30)	(7.13)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	10,784	10,454	330	3.16	10,988	10,704	284	2.65
37	GAS - Generation (1)	7,377	7,203	174	2.42	6,712	6,925	(213)	(3.08)
38	OIL - C.T.	0	0	0	0.00	16,234	0	16,234	100.00
39	TOTAL (BTU/KWH)	9,603	9,121	482	5.28	9,189	8,961	228	2.54
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	3.97	3.81	0.16	4.20	4.17	3.98	0.19	4.77
41	GAS	2.99	2.91	0.08	2.75	2.82	3.53	(0.71)	(20.11)
42	LANDFILL GAS	3.10	3.06	0.04	1.31	3.06	3.02	0.04	1.32
43	OIL - C.T.	0.00	0.00	0.00	0.00	30.62	0.00	30.62	100.00
44	TOTAL (¢/KWH)	3.62	3.44	0.18	5.23	3.60	3.77	(0.17)	(4.51)

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: JULY 2015

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2015	(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	(1,446)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
2				0					Gas-G	0	1,020	0	0	0.00	0.00
3									Gas-S	0	1,020	0	0		0.00
4									Oil-S	0	138,131	0	0		0.00
5	Crist 5		75	22,447	40.2	96.0	54.4	12,515	Coal	12,224	11,489	280,917	1,019,029	4.54	83.36
6				-					Gas-G	0	1,020	0	0	0.00	0.00
7									Gas-S	2,705	1,020	2,760	173,247		64.05
8									Oil-S	199	138,131	1,156	22,480		112.83
9	Crist 6		299	95,732	43.0	100.0	63.3	11,129	Coal	46,425	11,475	1,065,445	3,869,618	4.04	83.35
10				0					Gas-G	0	1,020	0	0	0.00	0.00
11									Gas-S	2,172	1,020	2,215	139,036		64.01
12									Oil-S	0	138,131	1	18		0.00
13	Crist 7		475	245,198	69.4	98.2	69.4	10,776	Coal	114,951	11,493	2,642,265	9,581,482	3.91	83.35
14				0					Gas-G	0	1,020	0	0	0.00	0.00
15									Gas-S	16	1,020	16	1,005		62.79
16									Oil-S	5	138,131	27	531		106.20
17	Scholz 1		46	0	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	0	0	0		0.00
19	Scholz 2		46	0	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	0	0	0		0.00
21	Smith 1		162	30,991	25.7	100.0	41.6	11,481	Coal	15,712.60	11,322	355,796	1,319,675	4.26	83.99
22									Oil-S	275	138,356	1,598	22,321		81.17
23	Smith 2		195	(825)	0.0	100.0	0.0	0	Coal	0	11,322	0	0	0.00	0.00
24									Oil-S	0	138,356	0	0		0.00
25	Smith 3		479	335,751	94.2	97.8	94.2	7,377	Gas-G	2,418,810	1,024	2,476,861	9,989,814	2.98	4.13
26	Smith A	(2)	32	(9)	0.0	100.0	0.0	0	Oil	0	138,219	0	0	0.00	0.00
27	Other Generation			5,947									222,899	3.75	0.00
28	Perdido			2,146					Landfill Gas				66,484	3.10	0.00
29	Daniel 1	(1)	255	117,782	62.1	100.0	62.1	10,169	Coal	57,651	10,388	1,197,700	4,390,785	3.73	76.16
30									Oil-S	0	140,012	1	9		0.00
31	Daniel 2	(1)	255	122,919	64.8	99.1	65.4	10,360	Coal	59,640	10,676	1,273,386	4,542,232	3.70	76.16
32									Oil-S	183	140,012	1,078	14,869		81.25
33	Total		2,394	976,633	54.8	95.1	58.6	9,603				9,301,222	35,375,534	3.62	

Notes & Adjust.: (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

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)	
	Recoverable Fuel	35,371,512	3.62

Docket No. 160001-EI
2015 Final True-Up Filing
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SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2015

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES :*								
2	UNITS (BBL)	1,045	940	105	11.17	12,596	5,663	6,933	122.43
3	UNIT COST ($/BBL)	75.46	84.72	(9.26)	(10.93)	78.37	116.39	(38.02)	(32.67)
4	AMOUNT ($)	78,856	79,641	(785)	(0.99)	987,113	659,097	328,016	49.77
5	*BURNED :*								
6	UNITS (BBL)	743	940	(197)	(20.96)	14,292	5,663	8,629	152.38
7	UNIT COST ($/BBL)	89.85	89.41	0.44	0.49	90.87	118.84	(27.97)	(23.54)
8	AMOUNT ($)	66,758	84,046	(17,288)	(20.57)	1,298,657	672,964	625,693	92.98
9	*ENDING INVENTORY :*								
10	UNITS (BBL)	5,301	4,998	303	6.06	5,301	4,998	303	6.06
11	UNIT COST ($/BBL)	95.35	97.83	(2.48)	(2.54)	95.35	97.83	(2.48)	(2.54)
12	AMOUNT ($)	505,440	488,937	16,503	3.38	505,440	488,937	16,503	3.38
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES :*								
15	UNITS (TONS)	264,150	296,419	(32,269)	(10.89)	1,281,553	1,224,383	57,170	4.67
16	UNIT COST ($/TON)	76.07	78.10	(2.03)	(2.60)	84.03	78.36	5.67	7.24
17	AMOUNT ($)	20,093,085	23,149,048	(3,055,963)	(13.20)	107,683,917	95,943,568	11,740,349	12.24
18	*BURNED :*								
19	UNITS (TONS)	306,604	237,673	68,931	29.00	1,442,470	1,240,177	202,293	16.31
20	UNIT COST ($/TON)	80.63	80.89	(0.26)	(0.32)	84.39	80.82	3.57	4.42
21	AMOUNT ($)	24,722,821	19,225,965	5,496,856	28.59	121,730,495	100,227,651	21,502,844	21.45
22	*ENDING INVENTORY :*								
23	UNITS (TONS)	395,545	496,746	(101,201)	(20.37)	395,545	496,746	(101,201)	(20.37)
24	UNIT COST ($/TON)	79.33	80.39	(1.06)	(1.32)	79.33	80.39	(1.06)	(1.32)
25	AMOUNT ($)	31,378,796	39,931,615	(8,552,819)	(21.42)	31,378,796	39,931,615	(8,552,819)	(21.42)
26	DAYS SUPPLY	19	24	(5)	(20.83)				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES :*								
28	UNITS (MMBTU)	2,474,563	2,591,455	(116,892)	(4.51)	15,548,566	15,361,225	187,341	1.22
29	UNIT COST ($/MMBTU)	4.13	4.10	0.03	0.73	3.88	5.16	(1.28)	(24.81)
30	AMOUNT ($)	10,220,586	10,618,909	(398,323)	(3.75)	60,292,246	79,317,644	(19,025,398)	(23.99)
31	*BURNED :*								
32	UNITS (MMBTU)	2,481,852	2,591,455	(109,603)	(4.23)	15,866,422	15,361,225	505,197	3.29
33	UNIT COST ($/MMBTU)	4.15	4.10	0.05	1.22	3.89	5.16	(1.27)	(24.61)
34	AMOUNT ($)	10,302,352	10,618,909	(316,557)	(2.98)	61,703,177	79,317,644	(17,614,467)	(22.21)
35	*ENDING INVENTORY :*								
36	UNITS (MMBTU)	723,486	0	723,486	100.00	723,486	0	723,486	100.00
37	UNIT COST ($/MMBTU)	4.03	0.00	4.03	100.00	4.03	0.00	4.03	100.00
38	AMOUNT ($)	2,917,785	0	2,917,785	100.00	2,917,785	0	2,917,785	100.00
	OTHER - C.T. OIL								
39	*PURCHASES :*								
40	UNITS (BBL) *	0	0	0	0.00	1,777	0	1,777	100.00
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	75.90	0.00	76.00	100.00
42	AMOUNT ($)	0	0	0	0.00	134,867	0	134,867	100.00
43	*BURNED :*								
44	UNITS (BBL)	0	0	0	0.00	2,039	0	2,039	100.00
45	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	109.92	0.00	109.92	100.00
46	AMOUNT ($)	0	0	0	0.00	224,117	0	224,117	100.00
47	*ENDING INVENTORY :*								
48	UNITS (BBL)	6,796	7,677	(881)	(11.48)	6,796	7,677	(881)	(11.48)
49	UNIT COST ($/BBL)	107.09	104.61	2.48	2.37	107.09	104.61	2.48	2.37
50	AMOUNT ($)	727,776	803,101	(75,325)	(9.38)	727,776	803,101	(75,325)	(9.38)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2015

			CURRENT MONTH						
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
				KWH		(a)	(b)	(5) x (6)(a)	(5) x (6)(b)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	¢ / KWH FUEL COST	¢ / KWH TOTAL COST	TOTAL $ FOR FUEL ADJ.	TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		204,353,000	0	204,353,000	3.03	3.22	6,196,000	6,581,000
2	Various	Economy Sales	6,403,000	0	6,403,000	2.92	3.15	187,000	202,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	88,000	88,000
4	TOTAL ESTIMATED SALES		210,756,000	0	210,756,000	3.07	3.26	6,471,000	6,871,000
	ACTUAL								
5	Southern Company Interchange		223,810,976	0	223,810,976	3.00	3.27	6,722,421	7,328,561
6	A.E.C.	External	1,517,467	0	1,517,467	2.55	3.22	38,624	48,912
7	AECI	External	0	0	0	0.00	0.00	0	0
8	AEP	External	0	0	0	0.00	0.00	0	0
9	BAM	External	0	0	0	0.00	0.00	0	0
10	CALPINE	External	0	0	0	0.00	0.00	0	0
11	CARGILE	External	36,675	0	36,675	3.20	4.49	1,175	1,647
12	DUKE PWR	External	13,264	0	13,264	9.30	4.70	1,234	623
13	EAGLE EN	External	168,388	0	168,388	2.50	3.50	4,203	5,893
14	ENDURE	External	23,212	0	23,212	3.50	5.56	813	1,290
15	EU	External	0	0	0	0.00	0.00	0	0
16	EXELON	External	156,454	0	156,454	3.29	4.10	5,140	6,412
17	FPC	External	0	0	0	0.00	0.00	0	0
18	FPL	External	189,285	0	189,285	3.48	5.06	6,593	9,579
19	JPMVEC	External	54,847	0	54,847	3.49	4.46	1,916	2,444
20	MISO	External	323,113	0	323,113	2.73	3.39	8,822	10,943
21	MORGAN	External	150,681	0	150,681	2.44	3.17	3,671	4,781
22	NCEMC	External	0	0	0	0.00	0.00	(0)	0
23	NCMPA1	External	0	0	0	0.00	0.00	0	0
24	NOBLEAGP	External	0	0	0	0.00	0.00	0	0
25	NRG	External	0	0	0	0.00	0.00	0	0
26	OPC	External	52,061	0	52,061	3.16	4.24	1,644	2,210
27	ORLANDO	External	0	0	0	0.00	0.00	4	0
28	PJM	External	241,340	0	241,340	3.21	5.16	7,742	12,447
29	SCE&G	External	704,094	0	704,094	2.56	3.08	18,022	21,677
30	SEC	External	20,029	0	20,029	1.84	2.66	368	533
31	SEPA	External	2,399,784	0	2,399,784	2.10	2.83	50,327	67,819
32	SPP	External	0	0	0	0.00	0.00	0	0
33	TAL	External	45,098	0	45,098	3.50	4.80	1,578	2,164
34	TEA	External	285,509	0	285,509	2.61	3.38	7,463	9,655
35	TECO	External	142,329	0	142,329	3.30	4.64	4,691	6,600
36	TENASKA	External	26,198	0	26,198	3.49	5.24	914	1,373
37	TVA	External	307,475	0	307,475	3.57		10,976	13,874
38	WRI	External	0	0	0	0.00	0.00	(50)	0
39	Less: Flow-Thru Energy		(6,153,209)	0	(6,153,209)	2.55	2.55	(156,778)	(156,778)
40	SEPA		1,013,496	1,013,496	0	0.00	0.00	0	0
41	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	82,970	82,970
42	Other transactions including adj.		208,150,550	167,319,157	40,831,393	0.00	0.00	0	0
43	TOTAL ACTUAL SALES		433,679,116	168,332,653	265,346,463	1.57	1.71	6,824,482	7,402,663
44	Difference in Amount		222,923,116	168,332,653	54,590,463	(1.50)	(1.55)	353,482	531,663
45	Difference in Percent		105.77	0.00	25.90	(48.86)	(47.55)	5.46	7.74

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 41

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2015

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		912,097,000	0	912,097,000	3.04	3.37	27,750,000	30,756,000
2	Various	Economy Sales	62,520,000	0	62,520,000	3.14	3.39	1,962,000	2,122,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	264,000	264,000
4	TOTAL ESTIMATED SALES		974,617,000	0	974,617,000	3.08	3.40	29,976,000	33,142,000
	ACTUAL								
5	Southern Company Interchange		1,350,501,732	0	1,350,501,732	2.90	3.17	39,218,680	42,813,887
6	A.E.C.	External	26,249,304	0	26,249,304	2.38	2.91	624,031	762,685
7	AECI	External	401,439	0	401,439	2.37	2.99	9,528	11,994
8	AEP	External	0	0	0	0.00	0.00	0	0
9	BAM	External	5,903	0	5,903	2.00	3.27	118	193
10	CALPINE	External	0	0	0	0.00	0.00	0	0
11	CARGILE	External	1,149,999	0	1,149,999	3.00	3.20	34,474	36,779
12	DUKE PWR	External	2,417,202	0	2,417,202	2.44	4.44	59,030	107,228
13	EAGLE EN	External	2,181,558	0	2,181,558	2.52	3.78	54,903	82,539
14	ENDURE	External	98,154	0	98,154	2.61	4.40	2,565	4,320
15	EU	External	12,535	0	12,535	1.56	2.43	195	305
16	EXELON	External	2,709,772	0	2,709,772	2.59	3.20	70,216	86,836
17	FPC	External	314,630	0	314,630	2.19	3.20	6,881	10,068
18	FPL	External	1,898,891	0	1,898,891	2.55	4.28	48,516	81,259
19	JPMVEC	External	887,638	0	887,638	2.47	3.19	21,939	28,334
20	MISO	External	2,465,819	0	2,465,819	2.11	3.13	51,966	77,226
21	MORGAN	External	3,450,165	0	3,450,165	2.39	2.88	82,526	99,384
22	NCEMC	External	1,388,060	0	1,388,060	2.34	3.27	32,545	45,330
23	NCMPA1	External	1,658	0	1,658	1.61	2.80	27	46
24	NOBLEAGP	External	26,528	0	26,528	1.59	2.80	422	743
25	NRG	External	0	0	0	0.00	0.00	0	0
26	OPC	External	858,403	0	858,403	2.48	3.74	21,297	32,064
27	ORLANDO	External	357,480	0	357,480	3.12	4.78	11,140	17,073
28	PJM	External	8,408,395	0	8,408,395	2.29	3.75	192,819	315,340
29	SCE&G	External	5,046,969	0	5,046,969	2.82	3.42	142,126	172,653
30	SEC	External	77,396	0	77,396	2.45	3.23	1,896	2,499
31	SEPA	External	7,076,691	0	7,076,691	2.03	2.95	143,880	208,579
32	SPP	External	0	0	0	0.00	0.00	0	0
33	TAL	External	251,363	0	251,363	2.28	3.95	5,739	9,933
34	TEA	External	10,911,626	0	10,911,626	2.18	3.25	238,410	355,000
35	TECO	External	979,904	0	979,904	2.33	3.54	22,788	34,725
36	TENASKA	External	46,824	0	46,824	3.07	4.42	1,440	2,070
37	TVA	External	3,587,629	0	3,587,629	2.46	3.99	88,322	142,998
38	WRI	External	1,748,728	0	1,748,728	1.97	2.68	34,498	46,870
39	Less: Flow-Thru Energy		(80,043,488)	0	(80,043,488)	2.29	2.29	(1,832,090)	(1,832,090)
40	SEPA		8,118,616	8,118,616	0	0.00	0.00	0	0
41	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	501,309	501,309
42	Other transactions including adj.		1,416,809,884	1,132,159,772	284,650,112	0.00	0.00	0	0
43	TOTAL ACTUAL SALES		2,780,397,407	1,140,278,388	1,640,119,019	1.43	1.57	39,892,134	43,756,870
44	Difference in Amount		1,805,780,407	1,140,278,388	665,502,019	(1.65)	(1.83)	9,916,134	10,614,870
45	Difference in Percent		185.28	0.00	68.28	(53.57)	(53.82)	33.08	32.03

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 41

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: JULY 2015

(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: JULY 2015

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.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	4,489,000	0	0	0	3.52	3.52	157,918
3	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	10
4	Ascend Performance Materials	COG 1	6,675,000	0	0	0	2.87	2.87	191,292
5	International Paper	COG 1	103,000	0	0	0	2.97	2.97	3,059
6	TOTAL		11,267,000	0	0	0	3.13	3.13	352,279

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.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	28,339,000	0	0	0	3.54	3.54	1,002,961
3	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	62
4	Ascend Performance Materials	COG 1	88,558,000	0	0	0	2.75	2.75	2,430,952
5	International Paper	COG 1	796,000	0	0	0	2.83	2.83	22,528
6	TOTAL		117,693,000	0	0	0	2.94	2.94	3,456,503

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: JULY 2015

		CURRENT MONTH			PERIOD - TO - DATE		
	(1) PURCHASED FROM	(2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	(5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	47,048,000	2.84	1,336,000	733,399,000	3.30	24,210,000
2	Economy Energy	4,601,000	3.28	151,000	25,939,000	3.51	911,000
3	Other Purchases	561,764,000	2.44	13,699,000	2,317,220,000	3.29	76,226,000
4	TOTAL ESTIMATED PURCHASES	613,413,000	2.48	15,186,000	3,076,558,000	3.29	101,347,000
	ACTUAL						
5	Southern Company Interchange	58,369,007	2.87	1,676,181	923,876,862	2.55	23,600,269
6	Non-Associated Companies	75,598,704	0.66	497,313	411,229,291	0.99	4,061,388
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	493,274,000	2.76	13,610,062	2,194,801,000	2.90	63,674,833
9	Other Wheeled Energy	66,615,000	0.00	N/A	381,154,000	0.00	N/A
10	Other Transactions	82,575,748	(0.01)	(5,648)	731,979,332	0.01	80,692
11	Less: Flow-Thru Energy	(6,153,209)	2.82	(173,364)	(80,043,488)	2.52	(2,020,865)
12	TOTAL ACTUAL PURCHASES	770,279,250	2.03	15,604,544	4,562,996,997	1.96	89,396,317
13	Difference in Amount	156,866,250	(0.45)	418,544	1,486,438,997	(1.33)	(11,950,683)
14	Difference in Percent	25.57	(18.15)	2.76	48.31	(40.43)	(11.79)

2015 CAPACITY CONTRACTS
GULF POWER COMPANY

	Capacity Costs ($)	CONTRACT	TERM		January	February	March	April	May	June	July	August	September	October	November	December	YTD
A.	CONTRACT/COUNTERPARTY	TYPE	Start	End													
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0	0	0	0	0	0	0						0
2	Power Purchase Agreements & Other Confidential Agreements				7,387,528	7,392,119	7,387,234	7,395,118	7,397,373	7,423,168	7,370,708						51,753,248
				Total	7,387,528	7,392,119	7,387,234	7,395,118	7,397,373	7,423,168	7,370,708						51,753,248

	Capacity Costs (MW)				January	February	March	April	May	June	July	August	September	October	November	December	YTD
B.	CONTRACT/COUNTERPARTY	TYPE	Start	End													
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0	0	0	0	0	0	0						0
2	Power Purchase Agreements & Other Confidential Agreements				Varies	Varies	Varies	Varies	Varies	Varies	Varies						

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 150001-EI

MONTHLY FUEL FILING

AUGUST 2015

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
AUGUST 2015

		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)	30,194,640	32,568,924	(2,374,284)	(7.29)	853,156,000	941,889,000	(88,733,000)	(9.42)	3.5392	3.4578	0.08	2.35
2	Hedging Settlement Costs (A2)	4,233,885	4,063,710	170,175	4.19	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	389	0	389	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	34,428,914	36,632,634	(2,203,720)	(6.02)	853,156,000	941,889,000	(88,733,000)	(9.42)	4.0355	3.8893	0.15	3.76
6	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
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	14,355,486.38	14,630,000	(274,514)	(1.88)	710,831,527	587,592,000	123,239,527	20.97	2.0195	2.4898	(0.47)	(18.89)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	460,244	0	460,244	100.00	15,097,000	0	15,097,000	100.00	3.0486	0.0000	3.05	0.00
12	TOTAL COST OF PURCHASED POWER	14,815,730	14,630,000	185,730	1.27	725,928,527	587,592,000	138,336,527	23.54	2.0409	2.4898	(0.45)	(18.03)
13	Total Available MWH (Line 5 + Line 12)	49,244,644	51,262,634	(2,017,990)	(3.94)	1,579,084,527	1,529,481,000	49,603,527	3.24				
14	Fuel Cost of Economy Sales (A6)	(146,748)	(238,000)	91,252	(38.34)	(6,016,033)	(8,494,000)	2,477,967	(29.17)	(2.4393)	(2.8020)	0.36	12.94
15	Gain on Economy Sales (A6)	(36,295)	(83,000)	46,705	(56.27)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(3,767,680)	(7,414,000)	3,646,320	(49.18)	(306,977,244)	(248,529,000)	(58,448,244)	23.52	(1.2273)	(2.9832)	1.76	58.86
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(3,950,723)	(7,735,000)	3,784,277	(48.92)	(312,993,277)	(257,023,000)	(55,970,277)	21.78	(1.2622)	(3.0095)	1.75	58.06
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	45,293,921	43,527,634	1,766,287	4.06	1,266,091,250	1,272,458,000	(6,366,750)	(0.50)	3.5775	3.4208	0.16	4.58
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	79,503	68,006	11,497	16.91	2,222,295	1,988,000	234,295	11.79	3.5775	3.4208	0.16	4.58
22	T & D Losses *	1,905,021	2,709,718	(804,697)	(29.70)	53,250,060	79,213,000	(25,962,940)	(32.78)	3.5775	3.4208	0.16	4.58
23	TERRITORIAL KWH SALES	45,293,921	43,527,634	1,766,287	4.06	1,210,618,895	1,191,257,000	19,361,895	1.63	3.7414	3.6539	0.09	2.39
24	Wholesale KWH Sales	1,203,414	1,209,154	(5,740)	(0.47)	32,164,697	33,092,000	(927,303)	(2.80)	3.7414	3.6539	0.09	2.39
25	Jurisdictional KWH Sales	44,090,507	42,318,480	1,772,027	4.19	1,178,454,198	1,158,165,000	20,289,198	1.75	3.7414	3.6539	0.09	2.39
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	44,156,643	42,381,958	1,774,685	4.19	1,178,454,198	1,158,165,000	20,289,198	1.75	3.7470	3.6594	0.09	2.39
28	TRUE-UP	3,996,375	3,996,375	0	0.00	1,178,454,198	1,158,165,000	20,289,198	1.75	0.3391	0.3451	(0.01)	(1.74)
29	TOTAL JURISDICTIONAL FUEL COST	48,153,018	46,378,333	1,774,685	3.83	1,178,454,198	1,158,165,000	20,289,198	1.75	4.0861	4.0045	0.08	2.04
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.0890	4.0074	0.08	2.04
32	GPIF Reward / (Penalty)	210,328	210,328	0	0.00	1,178,454,198	1,158,165,000	20,289,198	1.75	0.0178	0.0182	(0.00)	(2.20)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.1068	4.0256	0.08	2.02
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.107	4.026		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: AUGUST 2015

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 30,194,640
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	389
4	Hedging Settlement Costs	Schedule A-2, Line A-5	4,233,885
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	14,355,486
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	460,244
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(3,950,723)
10	Total Fuel and Net Power Transactions		$ 45,293,921

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
AUGUST 2015
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)	217,191,620	214,979,713	2,211,907	1.03	6,054,684,000	5,783,839,000	270,845,000	4.68	3.5872	3.7169	(0.13)	(3.49)
2	Hedging Settlement Costs (A2)	30,792,504	8,272,950	22,519,554	272.21	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	(103,476)	0	(103,476)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	247,880,648	223,252,663	24,627,985	11.03	6,054,684,000	5,783,839,000	270,845,000	4.68	4.0940	3.8599	0.23	6.06
6	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
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0.00	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	103,751,803	115,977,000	(12,225,197)	(10.54)	5,273,828,524	3,664,150,000	1,609,678,524	43.93	1.9673	3.1652	(1.20)	(37.85)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	3,916,747	0	3,916,747	100.00	132,790,000	0	132,790,000	100.00	2.9496	0.0000	2.95	0.00
12	TOTAL COST OF PURCHASED POWER	107,668,550	115,977,000	(8,308,450)	(7.16)	5,406,618,524	3,664,150,000	1,742,468,524	47.55	1.9914	3.1652	(1.17)	(37.08)
13	Total Available MWH (Line 5 + Line 12)	355,549,198	339,229,663	16,319,535	4.81	11,461,302,524	9,447,989,000	2,013,313,524	21.31				
14	Fuel Cost of Economy Sales (A6)	(2,150,981)	(2,200,000)	49,019	(2.23)	(91,026,696)	(71,014,000)	(20,012,696)	28.18	(2.3630)	(3.0980)	0.74	23.72
15	Gain on Economy Sales (A6)	(537,604)	(347,000)	(190,604)	54.93	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(41,154,270)	(35,164,000)	(5,990,270)	17.04	(3,002,363,988)	(1,160,626,000)	(1,841,737,988)	158.68	(1.3707)	(3.0297)	1.66	54.76
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(43,842,856.26)	(37,711,000)	(6,131,855)	16.26	(3,093,390,684)	(1,231,640,000)	(1,861,750,684)	151.16	(1.4173)	(3.0619)	1.64	53.71
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	311,706,342	301,518,663	10,187,679	3.38	8,367,911,840	8,216,349,000	151,562,840	1.84	3.7250	3.6697	0.06	1.51
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	583,502	523,384	60,118	11.49	15,664,487	14,262,300	1,402,187	9.83	3.7250	3.6697	0.06	1.51
22	T & D Losses *	14,013,281	16,828,646	(2,815,365)	(16.73)	376,195,460	458,583,700	(82,388,240)	(17.97)	3.7250	3.6697	0.06	1.51
23	TERRITORIAL KWH SALES	311,706,341	301,518,663	10,187,678	3.38	7,976,051,893	7,743,503,000	232,548,893	3.00	3.9080	3.8938	0.01	0.36
24	Wholesale KWH Sales	8,553,854	9,125,862	(572,008)	(6.27)	218,686,373	233,288,000	(14,601,627)	(6.26)	3.9115	3.9118	(0.00)	(0.01)
25	Jurisdictional KWH Sales	303,152,487	292,392,801	10,759,686	3.68	7,757,365,520	7,510,215,000	247,150,520	3.29	3.9079	3.8933	0.01	0.38
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	303,607,215	292,831,391	10,775,824	3.68	7,757,365,520	7,510,215,000	247,150,520	3.29	3.9138	3.8991	0.01	0.38
28	TRUE-UP	31,970,995	31,970,995	0	0.00	7,757,365,520	7,510,215,000	247,150,520	3.29	0.4121	0.4257	(0.01)	(3.19)
29	TOTAL JURISDICTIONAL FUEL COST	335,578,210	324,802,386	10,775,824	3.32	7,757,365,520	7,510,215,000	247,150,520	3.29	4.3259	4.3248	0.00	0.03
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.3290	4.3279	0.00	0.03
32	GPIF Reward / (Penalty)	1,682,626	1,682,626	0	0.00	7,757,365,520	7,510,215,000	247,150,520	3.29	0.0217	0.0224	(0.00)	(3.13)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.3507	4.3503	0.00	0.01
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.351	4.350		

* 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: AUGUST 2015

		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	29,975,036.81	32,263,161	(2,288,124.19)	(7.09)	215,388,146.56	212,945,810	2,442,336.56	1.15
1a	Other Generation	219,602.97	305,763	(86,160.03)	(28.18)	1,803,473.11	2,033,903	(230,429.89)	(11.33)
2	Fuel Cost of Power Sold	(3,950,723.10)	(7,735,000)	3,784,276.90	48.92	(43,842,856.98)	(37,711,000)	(6,131,856.98)	(16.26)
3	Fuel Cost - Purchased Power	14,355,486.02	14,630,000	(274,513.98)	(1.88)	103,751,802.52	115,977,000	(12,225,197.48)	(10.54)
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	460,244.29	0	460,244.29	100.00	3,916,747.38	0	3,916,747.38	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	4,233,885.00	4,063,710	170,175.00	4.19	30,792,504.43	8,272,950	22,519,554.43	272.21
6	Total Fuel & Net Power Transactions	45,293,531.99	43,527,634	1,765,897.99	4.06	311,809,817.02	301,518,663	10,291,154.02	3.41
7	AdjustmentsTo Fuel Cost*	389.21	0	389.21	100.00	(103,475.61)	0	(103,475.61)	100.00
8	Adj. Total Fuel & Net Power Transactions	45,293,921.20	43,527,634	1,766,287.20	4.06	311,706,341.41	301,518,663	10,187,678.41	3.38
B.	*KWH Sales*								
1	Jurisdictional Sales	1,178,454,198	1,158,165,000	20,289,198	1.75	7,757,365,520	7,510,215,000	247,150,520	3.29
2	Non-Jurisdictional Sales	32,164,697	33,092,000	(927,303)	(2.80)	218,686,373	233,288,000	(14,601,627)	(6.26)
3	Total Territorial Sales	1,210,618,895	1,191,257,000	19,361,895	1.63	7,976,051,893	7,743,503,000	232,548,893	3.00
4	Juris. Sales as % of Total Terr. Sales	97.3431	97.2221	0.1210	0.12	97.2582	96.9873	0.2709	0.28

**(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: AUGUST 2015

		CURRENT MONTH				PERIOD - TO - DATE			
		$		*DIFFERENCE*		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	52,090,907.23	50,172,645	1,918,262.45	3.82	335,725,961.55	325,348,590	10,377,371.85	3.19
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(3,996,375.00)	(3,996,375)	0.00	0.00	(31,970,995.00)	(31,970,995)	0.00	0.00
2b	Incentive Provision	(210,177.00)	(210,177)	0.00	0.00	(1,681,414.00)	(1,681,414)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	47,884,355.23	45,966,093	1,918,262.23	4.17	302,073,552.55	291,696,181	10,377,371.55	3.56
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	45,293,921.20	43,527,634	1,766,287.20	4.06	311,706,342.01	301,518,663	10,187,679.01	3.38
5	Juris. Sales % of Total KWH Sales (Line B4)	97.3431	97.2221	0.1210	0.12	97.2582	96.9873	0.2709	0.28
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	44,156,642.77	42,381,958	1,774,684.77	4.19	303,607,214.58	292,831,391	10,775,823.58	3.68
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	3,727,712.46	3,584,135	143,577.46	(4.01)	(1,533,662.03)	38,828,529	(40,362,191.03)	103.95
8	Interest Provision for the Month	(1,225.43)	(1,926)	700.57	36.37	(17,785.14)	(23,865)	6,079.86	25.48
9	Beginning True-Up & Interest Provision	(17,181,926.88)	(24,723,160)	7,541,233.12	30.50	(39,871,741.42)	(47,956,495)	8,084,753.58	16.86
10	True-Up Collected / (Refunded)	3,996,375.00	3,996,375	0.00	0.00	31,970,995.00	(7,992,745)	39,963,740.00	(500.00)
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(9,459,064.85)	(17,144,576)	7,685,511.15	44.83	(9,452,193.59)	(17,144,576)	7,692,382.41	44.87
12	Adjustment	0.00	0	0.00	0.00	(6,871.26)	0	(6,871.26)	100.00
13	End of Period - Total Net True-Up	(9,459,064.85)	(17,144,576)	7,685,511.15	44.83	(9,459,064.85)	(17,144,576)	7,685,511.15	44.83

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2015

		CURRENT MONTH			
		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(17,181,926.88)	(24,723,160)	7,541,233.12	(30.50)
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	(9,457,839.42)	(17,142,650)	7,684,810.58	(44.83)
3	Total of Beginning & Ending True-Up Amts.	(26,639,766.30)	(41,865,810)	15,226,043.70	(36.37)
4	Average True-Up Amount	(13,319,883.15)	(20,932,905)	7,613,021.85	(36.37)
	Interest Rate				
5	1st Day of Reporting Business Month	0.11	0.11	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.11	0.11	0.0000	
7	Total (D5+D6)	0.22	0.22	0.0000	
8	Annual Average Interest Rate	0.11	0.11	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0092	0.0092	0.0000	
10	Interest Provision (D4*D9)	(1,225.43)	(1,926)	700.57	(36.37)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0015		

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2015

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	50,837	83,911.00	(33,074)	(39.42)	1,303,488	756,875	546,613	72.22
2	COAL	19,550,713	21,498,637.00	(1,947,924)	(9.06)	141,332,477	121,726,288	19,606,189	16.11
3	GAS	10,193,960	10,636,369.00	(442,409)	(4.16)	72,470,711	90,191,615	(17,720,904)	(19.65)
4	GAS (B.L.)	331,854	285,768.00	46,086	16.13	1,347,401	1,776,306	(428,905)	(24.15)
5	LANDFILL GAS	67,276	64,239.00	3,037	4.73	513,423	528,629	(15,206)	(2.88)
6	OIL - C.T.	0	0	0	0.00	224,118	0	224,118	100.00
7	TOTAL ($)	30,194,640	32,568,924	(2,374,284)	(7.29)	217,191,620	214,979,713	2,211,907	1.03
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	505,065	577,776	(72,711)	(12.58)	3,483,011	3,152,911	330,100	10.47
10	GAS	345,967	362,013	(16,046)	(4.43)	2,554,259	2,613,456	(59,197)	(2.27)
11	LANDFILL GAS	2,134	2,100	34	1.62	16,692	17,472	(780)	(4.46)
12	OIL - C.T.	(10)	0	(10)	100.00	722	0	722	100.00
13	TOTAL (MWH)	853,156	941,889	(88,733)	(9.42)	6,054,684	5,783,839	270,845	4.68
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	605	940	(335)	(35.64)	14,421	6,603	7,818	118.40
15	COAL (TONS)	249,835	267,037	(17,202)	(6.44)	1,692,305	1,507,214	185,091	12.28
16	GAS (MCF) (1)	2,456,894	2,520,892	(63,998)	(2.54)	16,712,656	17,751,304	(1,038,648)	(5.85)
17	OIL - C.T. (BBL)	0	0	0	0.00	2,039	0	2,039	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	5,413,439	6,049,158	(635,719)	(10.51)	38,135,453	33,614,071	4,521,382	13.45
19	GAS - Generation (1)	2,499,449	2,551,310	(51,861)	(2.03)	17,025,298	17,812,535	(787,237)	(4.42)
20	OIL - C.T.	0	0	0	0.00	11,883	0	11,883	100.00
21	TOTAL (MMBTU)	7,912,888	8,600,468	(687,580)	(7.99)	55,172,634	51,426,606	3,746,028	7.28
	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	59.20	61.35	(2.15)	(3.50)	57.52	54.51	3.01	5.52
24	GAS	40.55	38.43	2.12	5.52	42.19	45.19	(3.00)	(6.64)
25	LANDFILL GAS	0.25	0.22	0.03	13.64	0.28	0.30	(0.02)	(6.67)
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)	83.98	89.27	(5.29)	(5.93)	90.39	114.63	(24.24)	(21.15)
29	COAL ($/TON)	78.25	80.51	(2.26)	(2.81)	83.51	80.76	2.75	3.41
30	GAS ($/MCF) (1)	4.19	4.21	(0.02)	(0.48)	4.31	5.07	(0.76)	(14.99)
31	OIL - C.T. ($/BBL)	0.00	0.00	0.00	0.00	109.92	0.00	109.92	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	3.68	3.62	0.06	1.66	3.78	3.70	0.08	2.16
33	GAS - Generation (1)	3.99	4.05	(0.06)	(1.48)	4.15	4.95	(0.80)	(16.16)
34	OIL - C.T.	0.00	0.00	0.00	0.00	18.86	0.00	18.86	100.00
35	TOTAL ($/MMBTU)	3.78	3.74	0.04	1.07	3.89	4.13	(0.24)	(5.81)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	10,718	10,470	248	2.37	10,949	10,661	288	2.70
37	GAS - Generation (1)	7,350	7,218	132	1.83	6,799	6,965	(166)	(2.38)
38	OIL - C.T.	0	0	0	0.00	16,458	0	16,458	100.00
39	TOTAL (BTU/KWH)	9,363	9,236	127	1.38	9,214	9,006	208	2.31
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	3.95	3.78	0.17	4.50	4.13	3.94	0.19	4.82
41	GAS	2.95	2.94	0.01	0.34	2.84	3.45	(0.61)	(17.68)
42	LANDFILL GAS	3.15	3.06	0.09	2.94	3.08	3.03	0.05	1.65
43	OIL - C.T.	0.00	0.00	0.00	0.00	31.04	0.00	31.04	100.00
44	TOTAL (¢/KWH)	3.54	3.46	0.08	2.31	3.59	3.72	(0.13)	(3.49)

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: AUGUST 2015

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2015	(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	(1,431)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
2				0					Gas-G	0	1,018	0	0	0.00	0.00
3									Gas-S	0	1,018	0	0		0.00
4									Oil-S	0	138,131	0	0		0.00
5	Crist 5		75	11,415	20.5	100.0	52.8	12,491	Coal	6,141	11,610	142,582	504,154	4.42	82.10
6				0					Gas-G	0	1,018	0	0	0.00	0.00
7									Gas-S	27	1,018	27	783		29.01
8									Oil-S	20	138,131	114	2,223		112.67
9	Crist 6		299	27,446	12.3	84.0	53.4	11,731	Coal	13,837	11,635	321,980	1,136,034	4.14	82.10
10				0					Gas-G	0	1,018	0	0	0.00	0.00
11									Gas-S	8,647	1,018	8,803	255,113		29.50
12									Oil-S	0	138,131	0	0		0.00
13	Crist 7		475	201,389	57.0	89.1	64.0	10,699	Coal	93,253	11,553	2,154,740	7,656,491	3.80	82.10
14				0					Gas-G	0	1,018	0	0	0.00	0.00
15									Gas-S	2,575	1,018	2,621	75,958		29.50
16									Oil-S	103	138,131	596	11,581		112.44
17	Scholz 1		0	0	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	0	0	0		0.00
19	Scholz 2		0	0	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	0	0	0		0.00
21	Smith 1		162	27,693	23.0	100.0	41.5	11,525	Coal	14,200.00	11,238	319,159	1,197,149	4.32	84.31
22									Oil-S	159	138,222	922	11,972		75.30
23	Smith 2		195	(718)	0.0	100.0	0.0	0	Coal	0	11,238	0	0	0.00	0.00
24									Oil-S	0	138,222	0	0		0.00
25	Smith 3		556	340,041	82.2	100.0	96.4	7,350	Gas-G	2,445,645	1,022	2,499,450	9,974,357	2.93	4.08
26	Smith A	(2)	32	(10)	0.0	100.0	0.0	0	Oil	0	138,219	0	0	0.00	0.00
27	Other Generation			5,926									219,603	3.71	0.00
28	Perdido			2,134					Landfill Gas				67,276	3.15	0.00
29	Daniel 1	(1)	255	92,961	49.0	85.2	57.4		Coal	50,623	9,645	976,518	3,747,341	4.03	74.02
30									Oil-S	323	139,250	1,888	24,962		77.28
31	Daniel 2	(1)	255	146,310	77.1	100.0	77.1	10,139	Coal	71,781	10,333	1,483,481	5,313,566	3.63	74.02
32									Oil-S	1	139,250	7	99		99.00
33	Total		2,379	853,156	48.2	94.2	60.9	9,363				7,912,888	30,198,662	3.54	

Notes & Adjust.: (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

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)	
	Recoverable Fuel	30,194,640	3.54

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2015

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES :*								
2	UNITS (BBL)	1,049	940	109	11.60	13,645	6,603	7,042	106.65
3	UNIT COST ($/BBL)	64.95	84.72	(19.77)	(23.34)	77.34	111.88	(34.54)	(30.87)
4	AMOUNT ($)	68,133	79,641	(11,508)	(14.45)	1,055,246	738,738	316,508	42.84
5	*BURNED :*								
6	UNITS (BBL)	674	940	(266)	(28.30)	14,966	6,603	8,363	126.65
7	UNIT COST ($/BBL)	83.06	89.27	(6.21)	(6.96)	90.51	114.63	(24.12)	(21.04)
8	AMOUNT ($)	55,981	83,911	(27,930)	(33.29)	1,354,638	756,875	597,763	78.98
9	*ENDING INVENTORY :*								
10	UNITS (BBL)	5,677	4,998	679	13.59	5,677	4,998	679	13.59
11	UNIT COST ($/BBL)	91.17	96.97	(5.80)	(5.98)	91.17	96.97	(5.80)	(5.98)
12	AMOUNT ($)	517,593	484,667	32,926	6.79	517,593	484,667	32,926	6.79
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES :*								
15	UNITS (TONS)	273,103	252,294	20,809	8.25	1,554,656	1,476,677	77,979	5.28
16	UNIT COST ($/TON)	76.89	79.95	(3.06)	(3.83)	82.77	78.63	4.14	5.27
17	AMOUNT ($)	21,000,093	20,170,314	829,779	4.11	128,684,010	116,113,882	12,570,128	10.83
18	*BURNED :*								
19	UNITS (TONS)	249,835	267,037	(17,202)	(6.44)	1,692,305	1,507,214	185,091	12.28
20	UNIT COST ($/TON)	78.27	80.51	(2.24)	(2.78)	83.49	80.76	2.73	3.38
21	AMOUNT ($)	19,554,735	21,498,637	(1,943,902)	(9.04)	141,285,230	121,726,288	19,558,942	16.07
22	*ENDING INVENTORY :*								
23	UNITS (TONS)	418,813	482,003	(63,190)	(13.11)	418,813	482,003	(63,190)	(13.11)
24	UNIT COST ($/TON)	78.37	80.09	(1.72)	(2.15)	78.37	80.09	(1.72)	(2.15)
25	AMOUNT ($)	32,824,155	38,603,292	(5,779,137)	(14.97)	32,824,155	38,603,292	(5,779,137)	(14.97)
26	DAYS SUPPLY	24	27	(3)	(11.11)				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES :*								
28	UNITS (MMBTU)	2,445,134	2,571,310	(126,176)	(4.91)	17,993,700	17,932,535	61,165	0.34
29	UNIT COST ($/MMBTU)	4.09	4.13	(0.04)	(0.97)	3.91	5.02	(1.11)	(22.11)
30	AMOUNT ($)	10,012,191	10,616,374	(604,183)	(5.69)	70,304,437	89,934,018	(19,629,581)	(21.83)
31	*BURNED :*								
32	UNITS (MMBTU)	2,510,900	2,571,310	(60,410)	(2.35)	18,377,322	17,932,535	444,787	2.48
33	UNIT COST ($/MMBTU)	4.10	4.13	(0.03)	(0.73)	3.92	5.02	(1.10)	(21.91)
34	AMOUNT ($)	10,305,461	10,616,374	(310,913)	(2.93)	72,008,638	89,934,018	(17,925,380)	(19.93)
35	*ENDING INVENTORY :*								
36	UNITS (MMBTU)	657,720	0	657,720	100.00	657,720	0	657,720	100.00
37	UNIT COST ($/MMBTU)	3.99	0.00	3.99	100.00	3.99	0.00	3.99	100.00
38	AMOUNT ($)	2,624,515	0	2,624,515	100.00	2,624,515	0	2,624,515	100.00
	OTHER - C.T. OIL								
39	*PURCHASES :*								
40	UNITS (BBL) *	0	0	0	0.00	1,777	0	1,777	100.00
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	75.90	0.00	76.00	100.00
42	AMOUNT ($)	0	0	0	0.00	134,867	0	134,867	100.00
43	*BURNED :*								
44	UNITS (BBL)	0	0	0	0.00	2,039	0	2,039	100.00
45	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	109.92	0.00	109.92	100.00
46	AMOUNT ($)	0	0	0	0.00	224,117	0	224,117	100.00
47	*ENDING INVENTORY :*								
48	UNITS (BBL)	6,796	7,677	(881)	(11.48)	6,796	7,677	(881)	(11.48)
49	UNIT COST ($/BBL)	107.09	104.61	2.48	2.37	107.09	104.61	2.48	2.37
50	AMOUNT ($)	727,776	803,101	(75,325)	(9.38)	727,776	803,101	(75,325)	(9.38)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2015

			CURRENT MONTH						
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
				KWH		(a)	(b)	(5) x (6)(a)	(5) x (6)(b)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	¢ / KWH FUEL COST	¢ / KWH TOTAL COST	TOTAL $ FOR FUEL ADJ.	TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		248,529,000	0	248,529,000	2.98	3.17	7,414,000	7,890,000
2	Various	Economy Sales	8,494,000	0	8,494,000	2.80	3.04	238,000	258,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	83,000	83,000
4	TOTAL ESTIMATED SALES		257,023,000	0	257,023,000	3.01	3.20	7,735,000	8,231,000
	ACTUAL								
5	Southern Company Interchange		130,162,736	0	130,162,736	3.00	3.30	3,902,255	4,291,678
6	A.E.C.	External	375,440	0	375,440	2.65	3.27	9,955	12,271
7	AECI	External	0	0	0	0.00	0.00	0	0
8	BAM	External	0	0	0	0.00	0.00	0	0
9	CARGILE	External	26,727	0	26,727	2.75	3.89	734	1,039
10	DUKE PWR	External	0	0	0	0.00	0.00	(716)	0
11	EAGLE EN	External	103,326	0	103,326	2.80	3.55	2,895	3,665
12	ENDURE	External	0	0	0	0.00	0.00	0	0
13	EU	External	0	0	0	0.00	0.00	0	0
14	EXELON	External	18,239	0	18,239	2.58	3.23	471	588
15	FPC	External	0	0	0	0.00	0.00	0	0
16	FPL	External	195,651	0	195,651	3.50	4.94	6,857	9,660
17	JPMVEC	External	23,743	0	23,743	2.59	3.17	615	752
18	MISO	External	144,047	0	144,047	2.26	2.64	3,255	3,807
19	MORGAN	External	51,067	0	51,067	2.09	2.98	1,069	1,523
20	NCEMC	External	4,974	0	4,974	2.99	3.64	149	181
21	NCMPA1	External	663	0	663	4.15	5.50	28	36
22	NOBLEAGP	External	0	0	0	0.00	0.00	0	0
23	OPC	External	33,162	0	33,162	2.32	3.82	768	1,267
24	ORLANDO	External	238,762	0	238,762	3.34	5.28	7,985	12,595
25	PJM	External	532,567	0	532,567	2.53	3.45	13,475	18,375
26	SCE&G	External	776,620	0	776,620	2.50	3.34	19,424	25,964
27	SEC	External	52,394	0	52,394	2.46	3.07	1,290	1,610
28	SEPA	External	2,219,931	0	2,219,931	2.20	2.93	48,947	64,956
29	TAL	External	1,658	0	1,658	2.36	4.20	39	70
30	TEA	External	990,639	0	990,639	2.47	3.33	24,472	32,989
31	TECO	External	61,346	0	61,346	2.73	4.04	1,675	2,475
32	TENASKA	External	0	0	0	0.00	0.00	0	0
33	TVA	External	45,099	0	45,099	2.25	4.33	1,016	1,952
34	WRI	External	119,978	0	119,978	1.95	2.75	2,345	3,298
35	Less: Flow-Thru Energy		(5,448,453)	0	(5,448,453)	2.47	2.47	(134,575)	(134,575)
36	SEPA		1,045,440	1,045,440	0	0.00	0.00	0	0
37	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	36,295	36,295
38	Other transactions including adj.		181,217,521	161,651,332	19,566,189	0.00	0.00	0	0
39	TOTAL ACTUAL SALES		312,993,277	162,696,772	150,296,505	1.26	1.39	3,950,723	4,356,177
40	Difference in Amount		55,970,277	162,696,772	(106,726,495)	(1.75)	(1.81)	(3,784,277)	(3,874,823)
41	Difference in Percent		21.78	0.00	(41.52)	(58.14)	(56.56)	(48.92)	(47.08)

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 37

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2015

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) c / KWH FUEL COST	(6) (b) c / KWH TOTAL COST	(7) TOTAL $ FOR FUEL ADJ.	(8) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		1,160,626,000	0	1,160,626,000	3.03	3.33	35,164,000	38,646,000
2	Various	Economy Sales	71,014,000	0	71,014,000	3.10	3.35	2,200,000	2,380,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	347,000	347,000
4	TOTAL ESTIMATED SALES		1,231,640,000	0	1,231,640,000	3.06	3.36	37,711,000	41,373,000
	ACTUAL								
5	Southern Company Interchange		1,480,664,468	0	1,480,664,468	2.91	3.18	43,120,934	47,105,565
6	A.E.C.	External	26,624,744	0	26,624,744	2.38	2.91	633,986	774,956
7	AECI	External	401,439	0	401,439	2.37	2.99	9,528	11,994
8	BAM	External	5,903	0	5,903	2.00	3.27	118	193
9	CARGILE	External	1,176,726	0	1,176,726	2.99	3.21	35,208	37,817
10	DUKE PWR	External	2,417,202	0	2,417,202	2.41	4.44	58,314	107,228
11	EAGLE EN	External	2,284,884	0	2,284,884	2.53	3.77	57,798	86,204
12	ENDURE	External	98,154	0	98,154	2.61	4.40	2,565	4,320
13	EU	External	12,535	0	12,535	1.56	2.43	195	305
14	EXELON	External	2,728,011	0	2,728,011	2.59	3.20	70,687	87,424
15	FPC	External	314,630	0	314,630	2.19	3.20	6,881	10,068
16	FPL	External	2,094,542	0	2,094,542	2.64	4.34	55,373	90,919
17	JPMVEC	External	911,381	0	911,381	2.47	3.19	22,555	29,086
18	MISO	External	2,609,866	0	2,609,866	2.12	3.10	55,221	81,033
19	MORGAN	External	3,501,232	0	3,501,232	2.39	2.88	83,595	100,907
20	NCEMC	External	1,393,034	0	1,393,034	2.35	3.27	32,693	45,511
21	NCMPA1	External	2,321	0	2,321	2.34	3.57	54	83
22	NOBLEAGP	External	26,528	0	26,528	1.59	2.80	422	743
23	OPC	External	891,565	0	891,565	2.47	3.74	22,065	33,331
24	ORLANDO	External	596,242	0	596,242	3.21	4.98	19,125	29,668
25	PJM	External	8,940,962	0	8,940,962	2.31	3.73	206,294	333,715
26	SCE&G	External	5,823,589	0	5,823,589	2.77	3.41	161,550	198,617
27	SEC	External	129,790	0	129,790	2.45	3.17	3,186	4,109
28	SEPA	External	9,296,622	0	9,296,622	2.07	2.94	192,826	273,536
29	TAL	External	253,021	0	253,021	2.28	3.95	5,778	10,003
30	TEA	External	11,902,265	0	11,902,265	2.21	3.26	262,882	387,989
31	TECO	External	1,041,250	0	1,041,250	2.35	3.57	24,463	37,200
32	TENASKA	External	46,824	0	46,824	3.07	4.42	1,440	2,070
33	TVA	External	3,632,728	0	3,632,728	2.46	3.99	89,338	144,950
34	WRI	External	1,868,706	0	1,868,706	1.97	2.68	36,843	50,168
35	Less: Flow-Thru Energy		(85,491,941)	0	(85,491,941)	2.30	2.30	(1,966,665)	(1,966,665)
36	SEPA		9,164,056	9,164,056	0	0.00	0.00	0	0
37	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	537,604	537,604
38	Other transactions including adj.		1,598,027,405	1,293,811,104	304,216,301	0.00	0.00	0	0
39	TOTAL ACTUAL SALES		3,093,390,684	1,302,975,160	1,790,415,524	1.42	1.56	43,842,856	48,113,048
40	Difference in Amount		1,861,750,684	1,302,975,160	558,775,524	(1.64)	(1.80)	6,131,856	6,740,048
41	Difference in Percent		151.16	0.00	45.37	(53.59)	(53.57)	16.26	16.29

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 37

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: AUGUST 2015

(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: AUGUST 2015

CURRENT MONTH

	(1) PURCHASED FROM:	(2) TYPE AND SCHEDULE	(3) TOTAL KWH PURCHASED	(4) KWH FOR OTHER UTILITIES	(5) KWH FOR INTERRUPTIBLE	(6) KWH FOR FIRM	(7) ¢/KWH (A) FUEL COST	(7) ¢/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	6,014,000	0	0	0	3.52	3.52	211,602
3	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
4	Ascend Performance Materials	COG 1	9,055,000	0	0	0	2.74	2.74	247,764
5	International Paper	COG 1	28,000	0	0	0	3.14	3.14	878
6	TOTAL		15,097,000	0	0	0	3.05	3.05	460,244

PERIOD-TO-DATE

	(1) PURCHASED FROM:	(2) TYPE AND SCHEDULE	(3) TOTAL KWH PURCHASED	(4) KWH FOR OTHER UTILITIES	(5) KWH FOR INTERRUPTIBLE	(6) KWH FOR FIRM	(7) ¢/KWH (A) FUEL COST	(7) ¢/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	34,353,000	0	0	0	3.54	3.54	1,214,563
3	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	62
4	Ascend Performance Materials	COG 1	97,613,000	0	0	0	2.74	2.74	2,678,716
5	International Paper	COG 1	824,000	0	0	0	2.84	2.84	23,406
6	TOTAL		132,790,000	0	0	0	2.95	2.95	3,916,747

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: AUGUST 2015

	(1) PURCHASED FROM	CURRENT MONTH (2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	PERIOD - TO - DATE (5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	24,396,000	3.80	926,000	757,795,000	3.32	25,136,000
2	Economy Energy	6,013,000	0.00	0	31,952,000	2.85	911,000
3	Other Purchases	557,183,000	2.46	13,704,000	2,874,403,000	3.13	89,930,000
4	TOTAL ESTIMATED PURCHASES	587,592,000	2.49	14,630,000	3,664,150,000	3.17	115,977,000
	ACTUAL						
5	Southern Company Interchange	87,861,221	2.33	2,049,420	1,011,738,083	2.54	25,649,689
6	Non-Associated Companies	71,947,643	0.70	500,776	483,176,934	0.94	4,562,164
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	427,366,000	2.79	11,934,864	2,622,167,000	2.88	75,609,697
9	Other Wheeled Energy	45,317,000	0.00	N/A	426,471,000	0.00	N/A
10	Other Transactions	83,788,116	0.02	17,561	815,767,448	0.01	98,253
11	Less: Flow-Thru Energy	(5,448,453)	2.70	(147,135)	(85,491,941)	2.54	(2,168,000)
12	TOTAL ACTUAL PURCHASES	710,831,527	2.02	14,355,486	5,273,828,524	1.97	103,751,803
13	Difference in Amount	123,239,527	(0.47)	(274,514)	1,609,678,524	(1.20)	(12,225,197)
14	Difference in Percent	20.97	(18.88)	(1.88)	43.93	(37.85)	(10.54)

2015 CAPACITY CONTRACTS
GULF POWER COMPANY

	Capacity Costs ($)	CONTRACT	TERM		January	February	March	April	May	June	July	August	September	October	November	December	YTD
A.	CONTRACT/COUNTERPARTY	TYPE	Start	End													
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0	0	0	0	0	0	0	0					0
2	Power Purchase Agreements & Other Confidential Agreements				7,387,528	7,392,119	7,387,234	7,395,118	7,397,373	7,423,168	7,370,708	7,371,907					59,125,155
				Total	7,387,528	7,392,119	7,387,234	7,395,118	7,397,373	7,423,168	7,370,708	7,371,907					59,125,155

	Capacity Costs (MW)				January	February	March	April	May	June	July	August	September	October	November	December	YTD
B.	CONTRACT/COUNTERPARTY	TYPE	Start	End													
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0	0	0	0	0	0	0	0					0
2	Power Purchase Agreements & Other Confidential Agreements				Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies					

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 150001-EI

MONTHLY FUEL FILING

SEPTEMBER 2015

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
SEPTEMBER 2015

		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)	23,169,242	23,882,049	(712,807)	(2.98)	698,701,000	702,249,000	(3,548,000)	(0.51)	3.3160	3.4008	(0.08)	(2.49)
2	Hedging Settlement Costs (A2)	4,378,195	3,792,620	585,575	15.44	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	153	0	153	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	27,547,590	27,674,669	(127,079)	(0.46)	698,701,000	702,249,000	(3,548,000)	(0.51)	3.9427	3.9409	0.00	0.05
6	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
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	13,878,300.44	14,497,000	(618,700)	(4.27)	705,186,331	583,616,000	121,570,331	20.83	1.9680	2.4840	(0.52)	(20.77)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	416,425	0	416,425	100.00	14,409,000	0	14,409,000	100.00	2.8900	0.0000	2.89	0.00
12	TOTAL COST OF PURCHASED POWER	14,294,725	14,497,000	(202,275)	(1.40)	719,595,331	583,616,000	135,979,331	23.30	1.9865	2.4840	(0.50)	(20.03)
13	Total Available MWH (Line 5 + Line 12)	41,842,315	42,171,669	(329,354)	(0.78)	1,418,296,331	1,285,865,000	132,431,331	10.30				
14	Fuel Cost of Economy Sales (A6)	(217,762)	(175,000)	(42,762)	24.44	(9,552,829)	(6,305,000)	(3,247,829)	51.51	(2.2796)	(2.7756)	0.50	17.87
15	Gain on Economy Sales (A6)	(34,267)	(55,000)	20,733	(37.70)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(4,327,853)	(4,828,000)	500,147	(10.36)	(335,200,190)	(163,629,000)	(171,571,190)	104.85	(1.2911)	(2.9506)	1.66	56.24
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(4,579,882)	(5,058,000)	478,118	(9.45)	(344,753,019)	(169,934,000)	(174,819,019)	102.87	(1.3285)	(2.9764)	1.65	55.37
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	37,262,433	37,113,669	148,764	0.40	1,073,543,312	1,115,931,000	(42,387,688)	(3.80)	3.4710	3.3258	0.15	4.37
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	72,298	58,135	14,163	24.36	2,082,913	1,748,000	334,913	19.16	3.4710	3.3258	0.15	4.37
22	T & D Losses *	1,773,630	2,052,185	(278,555)	(13.57)	51,098,527	61,705,000	(10,606,473)	(17.19)	3.4710	3.3258	0.15	4.37
23	TERRITORIAL KWH SALES	37,262,434	37,113,669	148,764	0.40	1,020,361,872	1,052,478,000	(32,116,128)	(3.05)	3.6519	3.5263	0.13	3.56
24	Wholesale KWH Sales	990,585	1,021,368	(30,783)	(3.01)	27,125,234	28,964,000	(1,838,766)	(6.35)	3.6519	3.5263	0.13	3.56
25	Jurisdictional KWH Sales	36,271,849	36,092,301	179,548	0.50	993,236,638	1,023,514,000	(30,277,362)	(2.96)	3.6519	3.5263	0.13	3.56
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	36,326,257	36,146,439	179,818	0.50	993,236,638	1,023,514,000	(30,277,362)	(2.96)	3.6574	3.5316	0.13	3.56
28	TRUE-UP	3,996,375	3,996,375	0	0.00	993,236,638	1,023,514,000	(30,277,362)	(2.96)	0.4024	0.3905	0.01	3.05
29	TOTAL JURISDICTIONAL FUEL COST	40,322,632	40,142,814	179,818	0.45	993,236,638	1,023,514,000	(30,277,362)	(2.96)	4.0598	3.9221	0.14	3.51
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.0627	3.9249	0.14	3.51
32	GPIF Reward / (Penalty)	210,328	210,328	0	0.00	993,236,638	1,023,514,000	(30,277,362)	(2.96)	0.0212	0.0205	0.00	3.41
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.0839	3.9454	0.14	3.51
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.084	3.945		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: SEPTEMBER 2015

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 23,169,242
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	153
4	Hedging Settlement Costs	Schedule A-2, Line A-5	4,378,195
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	13,878,300
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	416,425
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(4,579,882)
10	Total Fuel and Net Power Transactions		$ 37,262,433

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
SEPTEMBER 2015
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)	240,360,862	238,861,762	1,499,100	0.63	6,753,385,000	6,486,088,000	267,297,000	4.12	3.5591	3.6827	(0.12)	(3.36)
2	Hedging Settlement Costs (A2)	35,170,699	12,065,570	23,105,129	191.50	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	(103,323)	0	(103,323)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	275,428,238	250,927,332	24,500,906	9.76	6,753,385,000	6,486,088,000	267,297,000	4.12	4.0784	3.8687	0.21	5.42
6	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
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0.00	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	117,630,103	130,474,000	(12,843,897)	(9.84)	5,979,014,855	4,247,766,000	1,731,248,855	40.76	1.9674	3.0716	(1.10)	(35.95)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	4,333,172	0	4,333,172	100.00	147,199,000	0	147,199,000	100.00	2.9438	0.0000	2.94	0.00
12	TOTAL COST OF PURCHASED POWER	121,963,275	130,474,000	(8,510,725)	(6.52)	6,126,213,855	4,247,766,000	1,878,447,855	44.22	1.9908	3.0716	(1.08)	(35.19)
13	Total Available MWH (Line 5 + Line 12)	397,391,513	381,401,332	15,990,181	4.19	12,879,598,855	10,733,854,000	2,145,744,855	19.99				
14	Fuel Cost of Economy Sales (A6)	(2,368,744)	(2,375,000)	6,256	(0.26)	(100,579,525)	(77,319,000)	(23,260,525)	30.08	(2.3551)	(3.0717)	0.72	23.33
15	Gain on Economy Sales (A6)	(571,871)	(402,000)	(169,871)	42.26	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(45,482,123)	(39,992,000)	(5,490,123)	13.73	(3,337,564,178)	(1,324,255,000)	(2,013,309,178)	152.03	(1.3627)	(3.0200)	1.66	54.88
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(48,422,738.44)	(42,769,000)	(5,653,737)	13.22	(3,438,143,703)	(1,401,574,000)	(2,036,569,703)	145.31	(1.4084)	(3.0515)	1.64	53.85
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	348,968,775	338,632,332	10,336,443	3.05	9,441,455,152	9,332,280,000	109,175,152	1.17	3.6961	3.6286	0.07	1.86
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	655,962	580,950	75,012	12.91	17,747,400	16,010,300	1,737,100	10.85	3.6961	3.6286	0.07	1.86
22	T & D Losses *	15,793,213	18,879,196	(3,085,983)	(16.35)	427,293,987	520,288,700	(92,994,713)	(17.87)	3.6961	3.6286	0.07	1.86
23	TERRITORIAL KWH SALES	348,968,775	338,632,332	10,336,443	3.05	8,996,413,765	8,795,981,000	200,432,765	2.28	3.8790	3.8499	0.03	0.76
24	Wholesale KWH Sales	9,544,439	10,147,230	(602,791)	(5.94)	245,811,607	262,252,000	(16,440,393)	(6.27)	3.8828	3.8693	0.01	0.35
25	Jurisdictional KWH Sales	339,424,336	328,485,102	10,939,234	3.33	8,750,602,158	8,533,729,000	216,873,158	2.54	3.8789	3.8493	0.03	0.77
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	339,933,472	328,977,830	10,955,642	3.33	8,750,602,158	8,533,729,000	216,873,158	2.54	3.8847	3.8550	0.03	0.77
28	TRUE-UP	35,967,370	35,967,370	0	0.00	8,750,602,158	8,533,729,000	216,873,158	2.54	0.4110	0.4215	(0.01)	(2.49)
29	TOTAL JURISDICTIONAL FUEL COST	375,900,842	364,945,200	10,955,642	3.00	8,750,602,158	8,533,729,000	216,873,158	2.54	4.2957	4.2765	0.02	0.45
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.2988	4.2796	0.02	0.45
32	GPIF Reward / (Penalty)	1,892,954	1,892,954	0	0.00	8,750,602,158	8,533,729,000	216,873,158	2.54	0.0216	0.0222	(0.00)	(2.70)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.3204	4.3018	0.02	0.43
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.320	4.302		

* 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: SEPTEMBER 2015

		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	23,021,863.66	23,586,131	(564,267.34)	(2.39)	238,410,010.22	236,531,941	1,878,069.22	0.79
1a	Other Generation	147,378.56	295,918	(148,539.44)	(50.20)	1,950,851.67	2,329,821	(378,969.33)	(16.27)
2	Fuel Cost of Power Sold	(4,579,882.20)	(5,058,000)	478,117.80	9.45	(48,422,739.18)	(42,769,000)	(5,653,739.18)	(13.22)
3	Fuel Cost - Purchased Power	13,878,300.32	14,497,000	(618,699.68)	(4.27)	117,630,102.84	130,474,000	(12,843,897.16)	(9.84)
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	416,425.39	0	416,425.39	100.00	4,333,172.77	0	4,333,172.77	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	4,378,195.00	3,792,620	585,575.00	15.44	35,170,699.43	12,065,570	23,105,129.43	191.50
6	Total Fuel & Net Power Transactions	37,262,280.73	37,113,669	148,611.73	0.40	349,072,097.75	338,632,332	10,439,765.75	3.08
7	AdjustmentsTo Fuel Cost*	153.38	0	153.38	100.00	(103,322.23)	0	(103,322.23)	100.00
8	Adj. Total Fuel & Net Power Transactions	37,262,434.11	37,113,669	148,765.11	0.40	348,968,775.52	338,632,332	10,336,443.52	3.05
B.	*KWH Sales*								
1	Jurisdictional Sales	993,236,638	1,023,514,000	(30,277,362)	(2.96)	8,750,602,158	8,533,729,000	216,873,158	2.54
2	Non-Jurisdictional Sales	27,125,234	28,964,000	(1,838,766)	(6.35)	245,811,607	262,252,000	(16,440,393)	(6.27)
3	Total Territorial Sales	1,020,361,872	1,052,478,000	(32,116,128)	(3.05)	8,996,413,765	8,795,981,000	200,432,765	2.28
4	Juris. Sales as % of Total Terr. Sales	97.3416	97.2480	0.0936	0.10	97.2677	97.0185	0.2492	0.26

**(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: SEPTEMBER 2015

		CURRENT MONTH				PERIOD - TO - DATE			
				$ DIFFERENCE				$ DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	44,226,491.86	44,339,455	(112,962.66)	(0.25)	379,952,453.41	369,688,044	10,264,409.19	2.78
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(3,996,375.00)	(3,996,375)	0.00	0.00	(35,967,370.00)	(35,967,370)	0.00	0.00
2b	Incentive Provision	(210,177.00)	(210,177)	0.00	0.00	(1,891,591.00)	(1,891,591)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	40,019,939.86	40,132,903	(112,963.14)	(0.28)	342,093,492.41	331,829,083	10,264,409.41	3.09
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	37,262,434.11	37,113,669	148,765.11	0.40	348,968,776.12	338,632,332	10,336,444.12	3.05
5	Juris. Sales % of Total KWH Sales (Line B4)	97.3416	97.2480	0.0936	0.10	97.2677	97.0185	0.2492	0.26
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	36,326,257.34	36,146,439	179,818.34	0.50	339,933,471.92	328,977,830	10,955,641.92	3.33
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	3,693,682.52	3,986,464	(292,781.48)	7.34	2,160,020.49	42,814,993	(40,654,972.51)	94.95
8	Interest Provision for the Month	(561.40)	(1,315)	753.60	57.31	(18,346.54)	(25,180)	6,833.46	27.14
9	Beginning True-Up & Interest Provision	(9,459,064.85)	(17,144,576)	7,685,511.15	44.83	(39,871,741.42)	(47,956,495)	8,084,753.58	16.86
10	True-Up Collected / (Refunded)	3,996,375.00	3,996,375	0.00	0.00	35,967,370.00	(3,996,370)	39,963,740.00	(1,000.00)
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(1,769,568.73)	(9,163,052)	7,393,483.27	80.69	(1,762,697.47)	(9,163,052)	7,400,354.53	80.76
12	Adjustment	0.00	0	0.00	0.00	(6,871.26)	0	(6,871.26)	100.00
13	End of Period - Total Net True-Up	(1,769,568.73)	(9,163,052)	7,393,483.27	80.69	(1,769,568.73)	(9,163,052)	7,393,483.27	80.69

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2015

		CURRENT MONTH			
				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(9,459,064.85)	(17,144,576)	7,685,511.15	(44.83)
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	(1,769,007.33)	(9,161,737)	7,392,729.67	(80.69)
3	Total of Beginning & Ending True-Up Amts.	(11,228,072.18)	(26,306,313)	15,078,240.82	(57.32)
4	Average True-Up Amount	(5,614,036.09)	(13,153,157)	7,539,120.91	(57.32)
	Interest Rate				
5	1st Day of Reporting Business Month	0.11	0.11	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.13	0.13	0.0000	
7	Total (D5+D6)	0.24	0.24	0.0000	
8	Annual Average Interest Rate	0.12	0.12	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0100	0.0100	0.0000	
10	Interest Provision (D4*D9)	(561.40)	(1,315)	753.60	(57.31)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0015		

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2015

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	24,461	70,431.00	(45,970)	(65.27)	1,327,949	827,306	500,643	60.51
2	COAL	13,655,724	13,345,194.00	310,530	2.33	154,988,201	135,071,482	19,916,719	14.75
3	GAS	9,171,235	10,147,471.00	(976,236)	(9.62)	81,641,946	100,339,086	(18,697,140)	(18.63)
4	GAS (B.L.)	263,425	256,825.00	6,600	2.57	1,610,826	2,033,131	(422,305)	(20.77)
5	LANDFILL GAS	45,995	62,128.00	(16,133)	(25.97)	559,418	590,757	(31,339)	(5.30)
6	OIL - C.T.	8,402	0	8,402	100.00	232,520	0	232,520	100.00
7	TOTAL ($)	23,169,242	23,882,049	(712,807)	(2.98)	240,360,862	238,861,762	1,499,100	0.63
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	379,895	360,610	19,285	5.35	3,862,906	3,513,521	349,385	9.94
10	GAS	317,269	339,608	(22,339)	(6.58)	2,871,528	2,953,064	(81,536)	(2.76)
11	LANDFILL GAS	1,510	2,031	(521)	(25.65)	18,202	19,503	(1,301)	(6.67)
12	OIL - C.T.	27	0	27	100.00	749	0	749	100.00
13	TOTAL (MWH)	698,701	702,249	(3,548)	(0.51)	6,753,385	6,486,088	267,297	4.12
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	298	816	(518)	(63.48)	14,719	7,419	7,300	98.40
15	COAL (TONS)	175,187	169,447	5,740	3.39	1,867,492	1,676,661	190,831	11.38
16	GAS (MCF) (1)	2,276,065	2,352,005	(75,940)	(3.23)	18,988,721	20,103,309	(1,114,588)	(5.54)
17	OIL - C.T. (BBL)	78	0	78	100.00	2,117	0	2,117	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	4,124,372	3,793,156	331,216	8.73	42,259,824	37,407,227	4,852,597	12.97
19	GAS - Generation (1)	2,320,564	2,389,045	(68,481)	(2.87)	19,345,862	20,201,580	(855,718)	(4.24)
20	OIL - C.T.	455	0	455	100.00	12,338	0	12,338	100.00
21	TOTAL (MMBTU)	6,445,391	6,182,201	263,190	4.26	61,618,025	57,608,807	4,009,218	6.96
	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	54.37	51.35	3.02	5.88	57.20	54.17	3.03	5.59
24	GAS	45.41	48.36	(2.95)	(6.10)	42.52	45.53	(3.01)	(6.61)
25	LANDFILL GAS	0.22	0.29	(0.07)	(24.14)	0.27	0.30	(0.03)	(10.00)
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)	82.14	86.31	(4.17)	(4.83)	90.22	111.51	(21.29)	(19.09)
29	COAL ($/TON)	77.95	78.76	(0.81)	(1.03)	82.99	80.56	2.43	3.02
30	GAS ($/MCF) (1)	4.08	4.30	(0.22)	(5.12)	4.28	4.98	(0.70)	(14.06)
31	OIL - C.T. ($/BBL)	107.71	0.00	107.71	100.00	109.83	0.00	109.83	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	3.38	3.60	(0.22)	(6.11)	3.74	3.69	0.05	1.36
33	GAS - Generation (1)	3.89	4.12	(0.23)	(5.58)	4.12	4.85	(0.73)	(15.05)
34	OIL - C.T.	18.45	0.00	18.45	100.00	18.85	0.00	18.85	100.00
35	TOTAL ($/MMBTU)	3.56	3.81	(0.25)	(6.56)	3.86	4.10	(0.24)	(5.85)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	10,857	10,519	338	3.21	10,940	10,647	293	2.75
37	GAS - Generation (1)	7,401	7,211	190	2.63	6,866	6,994	(128)	(1.83)
38	OIL - C.T.	16,868	0	16,868	100.00	16,473	0	16,473	100.00
39	TOTAL (BTU/KWH)	9,295	8,935	360	4.03	9,222	8,998	224	2.49
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	3.67	3.79	(0.12)	(3.17)	4.09	3.93	0.16	4.07
41	GAS	2.89	2.99	(0.10)	(3.34)	2.84	3.40	(0.56)	(16.47)
42	LANDFILL GAS	3.05	3.06	(0.01)	(0.33)	3.07	3.03	0.04	1.32
43	OIL - C.T.	31.12	0.00	31.12	100.00	31.04	0.00	31.04	100.00
44	TOTAL (¢/KWH)	3.32	3.40	(0.08)	(2.35)	3.56	3.68	(0.12)	(3.26)

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: SEPTEMBER 2015

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2015	(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 ($)	(m) Fuel Cost/ KWH (c/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	(799)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
2				0					Gas-G	0	1,019	0	0	0.00	0.00
3									Gas-S	0	1,019	0	0		0.00
4									Oil-S	0	138,131	0	0		0.00
5	Crist 5		75	(780)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
6				0					Gas-G	0	1,019	0	0	0.00	0.00
7									Gas-S	0	1,019	0	0		0.00
8									Oil-S	0	138,131	0	0		0.00
9	Crist 6		299	81,718	38.0	99.7	54.9	11,700	Coal	40,892	11,691	956,130	3,314,845	4.06	81.06
10				0					Gas-G	327	1,019	333	26,646	0.00	0.00
11									Gas-S	2,096	1,019	2,136	170,922		81.55
12									Oil-S	4	138,131	23	449		112.25
13	Crist 7		475	193,205	56.5	100.0	56.5	10,598	Coal	87,977	11,637	2,047,605	7,131,864	3.69	81.07
14				0					Gas-G	0	1,019	0	0	0.00	0.00
15									Gas-S	1,134	1,019	1,156	92,504		81.57
16									Oil-S	37	138,131	211	4,099		110.78
17	Scholz 1		0	0	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	0	0	0		0.00
19	Scholz 2		0	0	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	0	0	0		0.00
21	Smith 1		162	(798)	0.0	100.0	0.0	0	Coal	0.00	0	0	0	0.00	0.00
22									Oil-S	0	138,222	0	0		0.00
23	Smith 2		195	(503)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
24									Oil-S	0	138,222	0	0		0.00
25	Smith 3		556	313,506	78.3	99.6	97.3	7,401	Gas-G	2,272,508	1,021	2,320,231	8,997,210	2.87	3.96
26	Smith A	(2)	32	27	0.1	94.2	84.4	16,852	Oil	78	138,219	455	8,402	31.12	107.72
27	Other Generation			3,737									147,379	3.94	0.00
28	Perdido			1,510					Landfill Gas				45,995	3.05	0.00
29	Daniel 1	(1)	255	31,697	17.3	100.0	52.2		Coal	16,990	9,376	318,577	1,228,533	3.88	72.31
30									Oil-S	20	139,035	118	1,563		78.15
31	Daniel 2	(1)	255	76,181	41.5	87.5	63.5	10,462	Coal	40,573	9,822	797,030	2,933,850	3.85	72.31
32									Oil-S	237	139,035	1,386	18,350		77.43
33	Total		2,379	698,701	40.8	98.4	54.5	9,295				6,445,391	24,122,610	3.45	

Notes & Adjust. (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

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)	
587	Inventory Adjustment - Crist	48,167	
(11,832)	Inventory Adjustment -Smith	(997,514)	
	Recoverable Fuel	23,169,242	3.32

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2015

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES:*								
2	UNITS (BBL)	0	816	(816)	(100.00)	13,645	7,419	6,226	83.92
3	UNIT COST ($/BBL)	0.00	84.67	(84.67)	(100.00)	77.37	108.89	(31.52)	(28.95)
4	AMOUNT ($)	509	69,093	(68,584)	(99.26)	1,055,755	807,831	247,924	30.69
5	*BURNED:*								
6	UNITS (BBL)	339	816	(477)	(58.46)	15,305	7,419	7,886	106.29
7	UNIT COST ($/BBL)	81.31	86.31	(5.00)	(5.79)	90.31	111.51	(21.20)	(19.01)
8	AMOUNT ($)	27,564	70,431	(42,867)	(60.86)	1,382,202	827,306	554,896	67.07
9	*ENDING INVENTORY:*								
10	UNITS (BBL)	5,338	4,998	340	6.80	5,338	4,998	340	6.80
11	UNIT COST ($/BBL)	91.90	96.70	(4.80)	(4.96)	91.90	96.70	(4.80)	(4.96)
12	AMOUNT ($)	490,538	483,329	7,209	1.49	490,538	483,329	7,209	1.49
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES:*								
15	UNITS (TONS)	254,150	167,450	86,700	51.78	1,808,806	1,644,127	164,679	10.02
16	UNIT COST ($/TON)	75.16	77.90	(2.74)	(3.52)	81.70	78.56	3.14	4.00
17	AMOUNT ($)	19,102,361	13,044,279	6,058,082	46.44	147,786,371	129,158,161	18,628,210	14.42
18	*BURNED:*								
19	UNITS (TONS)	175,187	169,447	5,740	3.39	1,867,492	1,676,661	190,831	11.38
20	UNIT COST ($/TON)	77.97	78.76	(0.79)	(1.00)	82.97	80.56	2.41	2.99
21	AMOUNT ($)	13,659,745	13,345,194	314,551	2.36	154,944,975	135,071,482	19,873,493	14.71
22	*ENDING INVENTORY:*								
23	UNITS (TONS)	497,776	480,006	17,770	3.70	497,776	480,006	17,770	3.70
24	UNIT COST ($/TON)	76.88	79.80	(2.92)	(3.66)	76.88	79.80	(2.92)	(3.66)
25	AMOUNT ($)	38,266,770	38,302,377	(35,607)	(0.09)	38,266,770	38,302,377	(35,607)	(0.09)
26	DAYS SUPPLY	28	27	1	3.70				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES:*								
28	UNITS (MMBTU)	2,304,073	2,399,045	(94,972)	(3.96)	20,297,773	20,331,580	(33,807)	(0.17)
29	UNIT COST ($/MMBTU)	3.96	4.21	(0.25)	(5.94)	3.91	4.92	(1.01)	(20.53)
30	AMOUNT ($)	9,135,553	10,108,378	(972,825)	(9.62)	79,439,990	100,042,396	(20,602,406)	(20.59)
31	*BURNED:*								
32	UNITS (MMBTU)	2,323,856	2,399,045	(75,189)	(3.13)	20,701,178	20,331,580	369,598	1.82
33	UNIT COST ($/MMBTU)	4.00	4.21	(0.21)	(4.99)	3.93	4.92	(0.99)	(20.12)
34	AMOUNT ($)	9,286,532	10,108,378	(821,846)	(8.13)	81,295,170	100,042,396	(18,747,226)	(18.74)
35	*ENDING INVENTORY:*								
36	UNITS (MMBTU)	637,937	0	637,937	100.00	637,937	0	637,937	100.00
37	UNIT COST ($/MMBTU)	3.88	0.00	3.88	100.00	3.88	0.00	3.88	100.00
38	AMOUNT ($)	2,473,536	0	2,473,536	100.00	2,473,536	0	2,473,536	100.00
	OTHER - C.T. OIL								
39	*PURCHASES:*								
40	UNITS (BBL) *	0	0	0	0.00	1,777	0	1,777	100.00
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	75.90	0.00	76.00	100.00
42	AMOUNT ($)	0	0	0	0.00	134,867	0	134,867	100.00
43	*BURNED:*								
44	UNITS (BBL)	78	0	78	100.00	2,117	0	2,117	100.00
45	UNIT COST ($/BBL)	107.72	0.00	107.72	100.00	109.83	0.00	109.83	100.00
46	AMOUNT ($)	8,402	0	8,402	100.00	232,519	0	232,519	100.00
47	*ENDING INVENTORY:*								
48	UNITS (BBL)	6,717	7,677	(960)	(12.50)	6,717	7,677	(960)	(12.50)
49	UNIT COST ($/BBL)	107.10	104.61	2.49	2.38	107.10	104.61	2.49	2.38
50	AMOUNT ($)	719,374	803,101	(83,727)	(10.43)	719,374	803,101	(83,727)	(10.43)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2015

			CURRENT MONTH						
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	(a) ¢ / KWH FUEL COST	(b) ¢ / KWH TOTAL COST	(5) x (6)(a) TOTAL $ FOR FUEL ADJ.	(5) x (6)(b) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		163,629,000	0	163,629,000	2.95	3.16	4,828,000	5,174,000
2	Various	Economy Sales	6,305,000	0	6,305,000	2.78	2.98	175,000	188,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	55,000	55,000
4	TOTAL ESTIMATED SALES		169,934,000	0	169,934,000	2.98	3.19	5,058,000	5,417,000
	ACTUAL								
5	Southern Company Interchange		174,770,132	0	174,770,132	2.59	2.79	4,519,807	4,884,287
6	A.E.C.	External	784,438	0	784,438	2.29	3.06	17,937	23,981
7	AECI	External	0	0	0	0.00	0.00	0	0
8	BAM	External	0	0	0	0.00	0.00	0	0
9	CARGILE	External	101,802	0	101,802	2.99	4.22	3,043	4,297
10	DUKE PWR	External	0	0	0	0.00	0.00	0	0
11	EAGLE EN	External	183,312	0	183,312	2.67	3.55	4,889	6,510
12	ENDURE	External	14,922	0	14,922	3.33	5.17	497	771
13	EU	External	0	0	0	0.00	0.00	0	0
14	EXELON	External	119,713	0	119,713	2.24	3.14	2,684	3,763
15	FPC	External	39,858	0	39,858	2.85	3.43	1,137	1,368
16	FPL	External	277,490	0	277,490	2.93	4.41	8,135	12,233
17	JPMVEC	External	21,222	0	21,222	3.21	4.21	680	893
18	MISO	External	105,582	0	105,582	2.56	3.37	2,705	3,554
19	MORGAN	External	173,430	0	173,430	2.68	3.41	4,654	5,908
20	NCEMC	External	38,797	0	38,797	2.22	2.87	861	1,112
21	NCMPA1	External	0	0	0	0.00	0.00	0	0
22	NOBLEAGP	External	0	0	0	0.00	0.00	0	0
23	OPC	External	97,823	0	97,823	2.76	4.03	2,695	3,939
24	ORLANDO	External	21,288	0	21,288	2.80	3.85	596	820
25	PJM	External	566,661	0	566,661	2.44	3.31	13,810	18,754
26	SCE&G	External	1,311,470	0	1,311,470	2.60	3.13	34,119	41,036
27	SEC	External	93,380	0	93,380	2.59	3.30	2,419	3,078
28	SEPA	External	3,834,915	0	3,834,915	1.89	2.67	72,598	102,221
29	TAL	External	0	0	0	0.00	0.00	0	0
30	TEA	External	1,342,662	0	1,342,662	2.44	3.42	32,786	45,895
31	TECO	External	251,296	0	251,296	2.93	3.95	7,365	9,927
32	TENASKA	External	6,632	0	6,632	3.70	5.35	246	355
33	TVA	External	86,222	0	86,222	2.48	3.33	2,140	2,872
34	WRI	External	79,914	0	79,914	2.21	2.92	1,766	2,334
35	Less: Flow-Thru Energy		(8,544,635)	0	(8,544,635)	2.25	2.25	(191,954)	(191,954)
36	SEPA		906,048	906,048	0	0.00	0.00	0	0
37	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	34,267	34,267
38	Other transactions including adj.		168,068,645	141,168,537	26,900,108	0.00	0.00	0	0
39	TOTAL ACTUAL SALES		344,753,019	142,074,585	202,678,434	1.33	1.45	4,579,882	4,987,957
40	Difference in Amount		174,819,019	142,074,585	32,744,434	(1.65)	(1.74)	(478,118)	(429,043)
41	Difference in Percent		102.87	0.00	19.27	(55.37)	(54.55)	(9.45)	(7.92)

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 37

SCHEDULE A-6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2015

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) c / KWH FUEL COST	(6) (b) c / KWH TOTAL COST	(7) TOTAL $ FOR FUEL ADJ.	(8) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		1,324,255,000	0	1,324,255,000	3.02	3.31	39,992,000	43,820,000
2	Various	Economy Sales	77,319,000	0	77,319,000	3.07	3.32	2,375,000	2,568,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	402,000	402,000
4	TOTAL ESTIMATED SALES		1,401,574,000	0	1,401,574,000	3.05	3.34	42,769,000	46,790,000
	ACTUAL								
5	Southern Company Interchange		1,655,434,600	0	1,655,434,600	2.88	3.14	47,640,741	51,989,852
6	A.E.C.	External	27,409,182	0	27,409,182	2.38	2.91	651,924	798,937
7	AECI	External	401,439	0	401,439	2.37	2.99	9,528	11,994
8	BAM	External	5,903	0	5,903	2.00	3.27	118	193
9	CARGILE	External	1,278,528	0	1,278,528	2.99	3.29	38,251	42,115
10	DUKE PWR	External	2,417,202	0	2,417,202	2.41	4.44	58,314	107,228
11	EAGLE EN	External	2,468,196	0	2,468,196	2.54	3.76	62,687	92,714
12	ENDURE	External	113,076	0	113,076	2.71	4.50	3,062	5,091
13	EU	External	12,535	0	12,535	1.56	2.43	195	305
14	EXELON	External	2,847,724	0	2,847,724	2.58	3.20	73,371	91,188
15	FPC	External	354,488	0	354,488	2.26	3.23	8,018	11,436
16	FPL	External	2,372,032	0	2,372,032	2.68	4.35	63,508	103,152
17	JPMVEC	External	932,603	0	932,603	2.49	3.21	23,235	29,978
18	MISO	External	2,715,448	0	2,715,448	2.13	3.12	57,926	84,587
19	MORGAN	External	3,674,662	0	3,674,662	2.40	2.91	88,249	106,815
20	NCEMC	External	1,431,831	0	1,431,831	2.34	3.26	33,555	46,623
21	NCMPA1	External	2,321	0	2,321	2.34	3.57	54	83
22	NOBLEAGP	External	26,528	0	26,528	1.59	2.80	422	743
23	OPC	External	989,388	0	989,388	2.50	3.77	24,760	37,270
24	ORLANDO	External	617,530	0	617,530	3.19	4.94	19,721	30,488
25	PJM	External	9,507,623	0	9,507,623	2.32	3.71	220,104	352,470
26	SCE&G	External	7,135,059	0	7,135,059	2.74	3.36	195,669	239,653
27	SEC	External	223,170	0	223,170	2.51	3.22	5,605	7,187
28	SEPA	External	13,131,537	0	13,131,537	2.02	2.86	265,424	375,756
29	TAL	External	253,021	0	253,021	2.28	3.95	5,778	10,003
30	TEA	External	13,244,927	0	13,244,927	2.23	3.28	295,668	433,884
31	TECO	External	1,292,546	0	1,292,546	2.46	3.65	31,828	47,127
32	TENASKA	External	53,456	0	53,456	3.15	4.54	1,685	2,425
33	TVA	External	3,718,950	0	3,718,950	2.46	3.97	91,478	147,823
34	WRI	External	1,948,620	0	1,948,620	1.98	2.69	38,609	52,502
35	Less: Flow-Thru Energy		(94,036,576)	0	(94,036,576)	2.30	2.30	(2,158,619)	(2,158,619)
36	SEPA		10,070,104	10,070,104	0	0.00	0.00	0	0
37	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	571,871	571,871
38	Other transactions including adj.		1,766,096,050	1,434,979,641	331,116,409	0.00	0.00	0	0
39	TOTAL ACTUAL SALES		3,438,143,703	1,445,049,745	1,993,093,958	1.41	1.54	48,422,739	53,101,004
40	Difference in Amount		2,036,569,703	1,445,049,745	591,519,958	(1.64)	(1.80)	5,653,739	6,311,004
41	Difference in Percent		145.31	0.00	42.20	(53.77)	(53.89)	13.22	13.49

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 37

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: SEPTEMBER 2015

(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: SEPTEMBER 2015

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.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	4,650,000	0	0	0	3.52	3.52	163,608
3	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
4	Ascend Performance Materials	COG 1	9,753,000	0	0	0	2.59	2.59	252,698
5	International Paper	COG 1	6,000	0	0	0	1.98	1.98	119
6	TOTAL		14,409,000	0	0	0	2.89	2.89	416,425

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.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	39,003,000	0	0	0	3.53	3.53	1,378,171
3	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	62
4	Ascend Performance Materials	COG 1	107,366,000	0	0	0	2.73	2.73	2,931,414
5	International Paper	COG 1	830,000	0	0	0	2.83	2.83	23,524
6	TOTAL		147,199,000	0	0	0	2.94	2.94	4,333,172

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: SEPTEMBER 2015

	(1)	CURRENT MONTH (2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	PERIOD - TO - DATE (5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	PURCHASED FROM						
	ESTIMATED						
1	Southern Company Interchange	66,968,000	2.63	1,760,000	824,763,000	3.26	26,896,000
2	Economy Energy	4,590,000	3.09	142,000	36,542,000	2.88	1,053,000
3	Other Purchases	512,058,000	2.46	12,595,000	3,386,461,000	3.03	102,525,000
4	TOTAL ESTIMATED PURCHASES	583,616,000	2.48	14,497,000	4,247,766,000	3.07	130,474,000
	ACTUAL						
5	Southern Company Interchange	100,881,798	2.23	2,246,820	1,112,619,881	2.51	27,896,508
6	Non-Associated Companies	57,263,094	0.73	420,774	540,440,028	0.92	4,982,939
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	429,214,000	2.66	11,414,642	3,051,381,000	2.85	87,024,339
9	Other Wheeled Energy	49,348,000	0.00	N/A	475,819,000	0.00	N/A
10	Other Transactions	77,024,074	0.01	9,691	892,791,522	0.01	107,944
11	Less: Flow-Thru Energy	(8,544,635)	2.50	(213,627)	(94,036,576)	2.53	(2,381,627)
12	TOTAL ACTUAL PURCHASES	705,186,331	1.97	13,878,300	5,979,014,855	1.97	117,630,103
13	Difference in Amount	121,570,331	(0.51)	(618,700)	1,731,248,855	(1.10)	(12,843,897)
14	Difference in Percent	20.83	(20.56)	(4.27)	40.76	(35.83)	(9.84)

2015 CAPACITY CONTRACTS
GULF POWER COMPANY

	Capacity Costs ($)	CONTRACT	TERM		January	February	March	April	May	June	July	August	September	October	November	December	YTD
A.	CONTRACT/COUNTERPARTY	TYPE	Start	End													
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0	0	0	0	0	0	0	0	0				0
2	Power Purchase Agreements & Other Confidential Agreements				7,387,528	7,392,119	7,387,234	7,395,118	7,397,373	7,423,168	7,370,708	7,371,907	7,370,740				66,495,895
				Total	7,387,528	7,392,119	7,387,234	7,395,118	7,397,373	7,423,168	7,370,708	7,371,907	7370740				66,495,895

	Capacity Costs (MW)				January	February	March	April	May	June	July	August	September	October	November	December	YTD
B.	CONTRACT/COUNTERPARTY	TYPE	Start	End													
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0	0	0	0	0	0	0	0	0				0
2	Power Purchase Agreements & Other Confidential Agreements				Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies				

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 150001-EI

MONTHLY FUEL FILING

October 2015

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
OCTOBER 2015

		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)	14,379,281	17,162,051	(2,782,770)	(16.21)	516,767,000	532,146,000	(15,379,000)	(2.89)	2.7825	3.2251	(0.44)	(13.72)
2	Hedging Settlement Costs (A2)	4,009,513	2,866,255	1,143,258	39.89	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	21	0	21	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	18,388,815	20,028,306	(1,639,491)	(8.19)	516,767,000	532,146,000	(15,379,000)	(2.89)	3.5584	3.7637	(0.21)	(5.45)
6	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
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	12,909,119.45	14,795,000	(1,885,881)	(12.75)	678,903,756	591,469,000	87,434,756	14.78	1.9015	2.5014	(0.60)	(23.98)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	493,218	0	493,218	100.00	18,016,000	0	18,016,000	100.00	2.7377	0.0000	2.74	0.00
12	TOTAL COST OF PURCHASED POWER	13,402,337	14,795,000	(1,392,663)	(9.41)	696,919,756	591,469,000	105,450,756	17.83	1.9231	2.5014	(0.58)	(23.12)
13	Total Available MWH (Line 5 + Line 12)	31,791,152	34,823,306	(3,032,154)	(8.71)	1,213,686,756	1,123,615,000	90,071,756	8.02				
14	Fuel Cost of Economy Sales (A6)	(187,204)	(226,000)	38,796	(17.17)	(9,272,998)	(9,958,000)	685,002	(6.88)	(2.0188)	(2.2695)	0.25	11.05
15	Gain on Economy Sales (A6)	(44,466)	(34,001)	(10,465)	30.78	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(3,192,729)	(4,290,000)	1,097,271	(25.58)	(312,583,272)	(201,023,000)	(111,560,272)	55.50	(1.0214)	(2.1341)	1.11	52.14
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(3,424,399)	(4,550,001)	1,125,601	(24.74)	(321,856,270)	(210,981,000)	(110,875,270)	52.55	(1.0640)	(2.1566)	1.09	50.66
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	28,366,753	30,273,305	(1,906,553)	(6.30)	891,830,486	912,634,000	(20,803,514)	(2.28)	3.1807	3.3171	(0.14)	(4.11)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	62,062	52,742	9,320	17.67	1,951,218	1,590,000	361,218	22.72	3.1807	3.3171	(0.14)	(4.11)
22	T & D Losses *	1,413,475	1,392,154	21,321	1.53	44,439,108	41,969,000	2,470,108	5.89	3.1807	3.3171	(0.14)	(4.11)
23	TERRITORIAL KWH SALES	28,366,752	30,273,305	(1,906,553)	(6.30)	845,440,160	869,075,000	(23,634,840)	(2.72)	3.3553	3.4834	(0.13)	(3.68)
24	Wholesale KWH Sales	773,277	863,727	(90,450)	(10.47)	23,046,822	24,796,000	(1,749,178)	(7.05)	3.3552	3.4833	(0.13)	(3.68)
25	Jurisdictional KWH Sales	27,593,475	29,409,578	(1,816,103)	(6.18)	822,393,338	844,279,000	(21,885,662)	(2.59)	3.3553	3.4834	(0.13)	(3.68)
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	27,634,865	29,453,692	(1,818,827)	(6.18)	822,393,338	844,279,000	(21,885,662)	(2.59)	3.3603	3.4886	(0.13)	(3.68)
28	TRUE-UP	3,996,375	3,996,375	0	0.00	822,393,338	844,279,000	(21,885,662)	(2.59)	0.4859	0.4733	0.01	2.66
29	TOTAL JURISDICTIONAL FUEL COST	31,631,240	33,450,067	(1,818,827)	(5.44)	822,393,338	844,279,000	(21,885,662)	(2.59)	3.8462	3.9619	(0.12)	(2.92)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.8490	3.9648	(0.12)	(2.92)
32	GPIF Reward / (Penalty)	210,328	210,328	0	0.00	822,393,338	844,279,000	(21,885,662)	(2.59)	0.0256	0.0249	0.00	2.81
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.8746	3.9897	(0.12)	(2.88)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.875	3.990		

* Included for Informational Purposes Only
**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: OCTOBER 2015

LINE	DESCRIPTION	REFERENCE		AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$	14,379,281
2	Fuel Related Transactions			0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7		21
4	Hedging Settlement Costs	Schedule A-2, Line A-5		4,009,513
5	Fuel Cost of Purchased Power	Schedule A-7		0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12		12,909,119
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9		0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7		493,218
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line		(3,424,400)
10	Total Fuel and Net Power Transactions		$	28,366,752

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
OCTOBER 2015
PERIOD TO DATE

		DOLLARS		DIFFERENCE		KWH		DIFFERENCE		CENTS/KWH		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)	254,740,143	256,023,813	(1,283,670)	(0.50)	7,270,152,000	7,018,234,000	251,918,000	3.59	3.5039	3.6480	(0.14)	(3.95)
2	Hedging Settlement Costs (A2)	39,180,212	14,931,825	24,248,387	162.39	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	(103,302)	0	(103,302)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	293,817,053	270,955,638	22,861,415	8.44	7,270,152,000	7,018,234,000	251,918,000	3.59	4.0414	3.8607	0.18	4.68
6	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
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0.00	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	130,539,222	145,269,000	(14,729,778)	(10.14)	6,657,918,611	4,839,235,000	1,818,683,611	37.58	1.9607	3.0019	(1.04)	(34.68)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	4,826,390	0	4,826,390	100.00	165,215,000	0	165,215,000	100.00	2.9213	0.0000	2.92	0.00
12	TOTAL COST OF PURCHASED POWER	135,365,612	145,269,000	(9,903,388)	(6.82)	6,823,133,611	4,839,235,000	1,983,898,611	41.00	1.9839	3.0019	(1.02)	(33.91)
13	Total Available MWH (Line 5 + Line 12)	429,182,666	416,224,638	12,958,028	3.11	14,093,285,611	11,857,469,000	2,235,816,611	18.86				
14	Fuel Cost of Economy Sales (A6)	(2,555,948)	(2,601,000)	45,052	(1.73)	(109,852,523)	(87,277,000)	(22,575,523)	25.87	(2.3267)	(2.9802)	0.65	21.93
15	Gain on Economy Sales (A6)	(616,337)	(436,001)	(180,336)	41.36	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(48,674,852)	(44,282,000)	(4,392,852)	9.92	(3,650,147,450)	(1,525,278,000)	(2,124,869,450)	139.31	(1.3335)	(2.9032)	1.57	54.07
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(51,847,137.88)	(47,319,001)	(4,528,136)	9.57	(3,759,999,973)	(1,612,555,000)	(2,147,444,973)	133.17	(1.3789)	(2.9344)	1.56	53.01
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	377,335,528	368,905,637	8,429,891	2.29	10,333,285,638	10,244,914,000	88,371,638	0.86	3.6517	3.6009	0.05	1.41
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	719,334	633,769	85,565	13.50	19,698,618	17,600,300	2,098,318	11.92	3.6517	3.6009	0.05	1.41
22	T & D Losses *	17,226,277	20,246,338	(3,020,061)	(14.92)	471,733,095	562,257,700	(90,524,605)	(16.10)	3.6517	3.6009	0.05	1.41
23	TERRITORIAL KWH SALES	377,335,527	368,905,637	8,429,890	2.29	9,841,853,925	9,665,056,000	176,797,925	1.83	3.8340	3.8169	0.02	0.45
24	Wholesale KWH Sales	10,317,716	11,010,957	(693,241)	(6.30)	268,858,429	287,048,000	(18,189,571)	(6.34)	3.8376	3.8359	0.00	0.04
25	Jurisdictional KWH Sales	367,017,811	357,894,680	9,123,131	2.55	9,572,995,496	9,378,008,000	194,987,496	2.08	3.8339	3.8163	0.02	0.46
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	367,568,337	358,431,522	9,136,815	2.55	9,572,995,496	9,378,008,000	194,987,496	2.08	3.8396	3.8220	0.02	0.46
28	TRUE-UP	39,963,745	39,963,745	0	0.00	9,572,995,496	9,378,008,000	194,987,496	2.08	0.4175	0.4261	(0.01)	(2.02)
29	TOTAL JURISDICTIONAL FUEL COST	407,532,082	398,395,267	9,136,815	2.29	9,572,995,496	9,378,008,000	194,987,496	2.08	4.2571	4.2481	0.01	0.21
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.2602	4.2512	0.01	0.21
32	GPIF Reward / (Penalty)	2,103,282	2,103,282	0	0.00	9,572,995,496	9,378,008,000	194,987,496	2.08	0.0220	0.0224	(0.00)	(1.79)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.2822	4.2736	0.01	0.20
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.282	4.274		

* 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: OCTOBER 2015

		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	14,192,849.31	16,958,019	(2,765,169.69)	(16.31)	252,602,859.53	253,489,960	(887,100.47)	(0.35)
1a	Other Generation	186,431.94	204,032	(17,600.06)	(8.63)	2,137,283.61	2,533,853	(396,569.39)	(15.65)
2	Fuel Cost of Power Sold	(3,424,399.63)	(4,550,001)	1,125,601.37	24.74	(51,847,138.81)	(47,319,001)	(4,528,137.81)	(9.57)
3	Fuel Cost - Purchased Power	12,909,119.50	14,795,000	(1,885,880.50)	(12.75)	130,539,222.34	145,269,000	(14,729,777.66)	(10.14)
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	493,217.58	0	493,217.58	100.00	4,826,390.35	0	4,826,390.35	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	4,009,513.00	2,866,255	1,143,258.00	39.89	39,180,212.43	14,931,825	24,248,387.43	162.39
6	Total Fuel & Net Power Transactions	28,366,731.70	30,273,305	(1,906,573.30)	(6.30)	377,438,829.45	368,905,637	8,533,192.45	2.31
7	AdjustmentsTo Fuel Cost*	20.61	0	20.61	100.00	(103,301.62)	0	(103,301.62)	100.00
8	Adj. Total Fuel & Net Power Transactions	28,366,752.31	30,273,305	(1,906,552.69)	(6.30)	377,335,527.83	368,905,637	8,429,890.83	2.29
B.	*KWH Sales*								
1	Jurisdictional Sales	822,393,338	844,279,000	(21,885,662)	(2.59)	9,572,995,496	9,378,008,000	194,987,496	2.08
2	Non-Jurisdictional Sales	23,046,822	24,796,000	(1,749,178)	(7.05)	268,858,429	287,048,000	(18,189,571)	(6.34)
3	Total Territorial Sales	845,440,160	869,075,000	(23,634,840)	(2.72)	9,841,853,925	9,665,056,000	176,797,925	1.83
4	Juris. Sales as % of Total Terr. Sales	97.2740	97.1469	0.1271	0.13	97.2682	97.0300	0.2382	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: OCTOBER 2015

		CURRENT MONTH				PERIOD - TO - DATE			
				$ DIFFERENCE				$ DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	35,081,950.36	36,574,849	(1,492,898.96)	(4.08)	415,034,403.77	406,262,894	8,771,510.24	2.16
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(3,996,375.00)	(3,996,375)	0.00	0.00	(39,963,745.00)	(39,963,745)	0.00	0.00
2b	Incentive Provision	(210,177.00)	(210,177)	0.00	0.00	(2,101,768.00)	(2,101,768)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	30,875,398.36	32,368,297	(1,492,898.64)	(4.61)	372,968,890.77	364,197,381	8,771,509.77	2.41
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	28,366,752.31	30,273,305	(1,906,552.69)	(6.30)	377,335,528.43	368,905,637	8,429,891.43	2.29
5	Juris. Sales % of Total KWH Sales (Line B4)	97.2740	97.1469	0.1271	0.13	97.2682	97.0300	0.2382	0.25
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	27,634,864.85	29,453,692	(1,818,827.15)	(6.18)	367,568,336.77	358,431,522	9,136,814.77	2.55
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	3,240,533.51	2,914,605	325,928.51	(11.18)	5,400,554.00	45,729,598	(40,329,044.00)	88.19
8	Interest Provision for the Month	192.28	(594)	786.28	132.37	(18,154.26)	(25,774)	7,619.74	29.56
9	Beginning True-Up & Interest Provision	(1,769,568.73)	(9,163,052)	7,393,483.27	80.69	(39,871,741.42)	(47,956,495)	8,084,753.58	16.86
10	True-Up Collected / (Refunded)	3,996,375.00	3,996,375	0.00	0.00	39,963,745.00	5	39,963,740.00	799,274,800.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	5,467,532.06	(2,252,666)	7,720,198.06	342.71	5,474,403.32	(2,252,666)	7,727,069.32	343.02
12	Adjustment	0.00	0	0.00	0.00	(6,871.26)	0	(6,871.26)	100.00
13	End of Period - Total Net True-Up	5,467,532.06	(2,252,666)	7,720,198.06	342.71	5,467,532.06	(2,252,666)	7,720,198.06	342.71

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2015

		CURRENT MONTH			
		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	(1,769,568.73)	(9,163,052)	7,393,483.27	(80.69)
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	5,467,339.78	(2,252,072)	7,719,411.78	(342.77)
3	Total of Beginning & Ending True-Up Amts.	3,697,771.05	(11,415,124)	15,112,895.05	(132.39)
4	Average True-Up Amount	1,848,885.53	(5,707,562)	7,556,447.53	(132.39)
	Interest Rate				
5	1st Day of Reporting Business Month	0.13	0.13	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.12	0.12	0.0000	
7	Total (D5+D6)	0.25	0.25	0.0000	
8	Annual Average Interest Rate	0.13	0.13	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0104	0.0104	0.0000	
10	Interest Provision (D4*D9)	192.28	(594)	786.28	(132.37)
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0015		

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2015

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	28,782	49,262.00	(20,480)	(41.57)	1,356,731	876,568	480,163	54.78
2	COAL	4,430,575	6,496,947.00	(2,066,372)	(31.81)	159,418,776	141,568,429	17,850,347	12.61
3	GAS	9,510,779	10,309,145.00	(798,366)	(7.74)	91,152,725	110,648,231	(19,495,506)	(17.62)
4	GAS (B.L.)	323,609	242,458.00	81,151	33.47	1,934,435	2,275,589	(341,154)	(14.99)
5	LANDFILL GAS	59,219	64,239.00	(5,020)	(7.81)	618,638	654,996	(36,358)	(5.55)
6	OIL - C.T.	26,317	0	26,317	100.00	258,837	0	258,837	100.00
7	TOTAL ($)	14,379,281	17,162,051	(2,782,770)	(16.21)	254,740,143	256,023,813	(1,283,670)	(0.50)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	138,946	181,619	(42,673)	(23.50)	4,001,852	3,695,140	306,712	8.30
10	GAS	375,877	348,427	27,450	7.88	3,247,405	3,301,491	(54,086)	(1.64)
11	LANDFILL GAS	1,917	2,100	(183)	(8.71)	20,119	21,603	(1,484)	(6.87)
12	OIL - C.T.	27	0	27	100.00	776	0	776	100.00
13	TOTAL (MWH)	516,767	532,146	(15,379)	(2.89)	7,270,152	7,018,234	251,918	3.59
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	258	567	(309)	(54.50)	14,977	7,986	6,991	87.54
15	COAL (TONS)	55,361	87,123	(31,762)	(36.46)	1,922,853	1,763,784	159,069	9.02
16	GAS (MCF) (1)	2,638,010	2,400,299	237,711	9.90	21,626,731	22,503,608	(876,877)	(3.90)
17	OIL - C.T. (BBL)	251	0	251	100.00	2,368	0	2,368	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	1,610,812	1,915,162	(304,350)	(15.89)	43,870,636	39,322,389	4,548,247	11.57
19	GAS - Generation (1)	2,685,485	2,443,305	242,180	9.91	22,031,347	22,644,885	(613,538)	(2.71)
20	OIL - C.T.	1,457	0	1,457	100.00	13,796	0	13,796	100.00
21	TOTAL (MMBTU)	4,297,755	4,358,467	(60,712)	(1.39)	65,915,779	61,967,274	3,948,505	6.37
	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	26.88	34.13	(7.25)	(21.24)	55.04	52.65	2.39	4.54
24	GAS	72.74	65.48	7.26	11.09	44.67	47.04	(2.37)	(5.04)
25	LANDFILL GAS	0.37	0.39	(0.02)	(5.13)	0.28	0.31	(0.03)	(9.68)
26	OIL - C.T.	0.01	0.00	0.01	100.00	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)	111.59	86.88	24.71	28.44	90.59	109.76	(19.17)	(17.47)
29	COAL ($/TON)	80.03	74.57	5.46	7.32	82.91	80.26	2.65	3.30
30	GAS ($/MCF) (1)	3.66	4.31	(0.65)	(15.08)	4.21	4.91	(0.70)	(14.26)
31	OIL - C.T. ($/BBL)	104.85	0.00	104.85	100.00	109.31	0.00	109.31	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	2.97	3.54	(0.57)	(16.10)	3.71	3.68	0.03	0.82
33	GAS - Generation (1)	3.47	4.14	(0.67)	(16.18)	4.04	4.77	(0.73)	(15.30)
34	OIL - C.T.	18.06	0.00	18.06	100.00	18.76	0.00	18.76	100.00
35	TOTAL ($/MMBTU)	3.29	3.88	(0.59)	(15.21)	3.82	4.08	(0.26)	(6.37)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	11,593	10,545	1,048	9.94	10,963	10,642	321	3.02
37	GAS - Generation (1)	7,244	7,129	115	1.61	6,910	7,008	(98)	(1.40)
38	OIL - C.T.	53,977	0	53,977	100.00	17,778	0	17,778	100.00
39	TOTAL (BTU/KWH)	8,432	8,313	119	1.43	9,166	8,946	220	2.46
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	3.44	3.74	(0.30)	(8.02)	4.07	3.92	0.15	3.83
41	GAS	2.53	2.96	(0.43)	(14.53)	2.81	3.35	(0.54)	(16.12)
42	LANDFILL GAS	3.09	3.06	0.03	0.98	3.07	3.03	0.04	1.32
43	OIL - C.T.	97.47	0.00	97.47	100.00	33.36	0.00	33.36	100.00
44	TOTAL (¢/KWH)	2.78	3.23	(0.45)	(13.93)	3.50	3.65	(0.15)	(4.11)

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: OCTOBER 2015

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2015	(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	(409)	0.0	74.6	0.0	0	Coal	0	0	0	0	0.00	0.00
2				0					Gas-G	0	1,016	0	0	0.00	0.00
3									Gas-S	4,964	1,016	5,043	206,997		41.70
4									Oil-S	185	138,131	1,073	20,876		112.84
5	Crist 5		75	(651)	0.0	93.2	0.0	0	Coal	0	0	0	0	0.00	0.00
6				0					Gas-G	0	1,016	0	0	0.00	0.00
7									Gas-S	2,794	1,016	2,839	116,532		41.71
8									Oil-S	56	138,131	327	6,367		112.91
9	Crist 6		299	26,213	11.8	87.0	52.4	12,164	Coal	13,725	11,616	318,854	1,115,710	4.26	81.29
10				0					Gas-G	0	1,016	0	0	0.00	0.00
11									Gas-S	2	1,016	2	81		40.45
12									Oil-S	0	138,131	0	0		0.00
13	Crist 7		475	95,044	26.9	54.8	51.6	11,133	Coal	44,863	11,793	1,058,145	3,647,016	3.84	81.29
14				0					Gas-G	0	1,016	0	0	0.00	0.00
15									Gas-S	0	1,016	0	0		0.00
16									Oil-S	7	138,131	41	804		114.86
17	Scholz 1		0	0	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	0	0	0		0.00
19	Scholz 2		0	0	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	0	0	0		0.00
21	Smith 1		162	(806)	0.0	98.8	0.0	0	Coal	0.00	0	0	0	0.00	0.00
22									Oil-S	0	138,222	0	0		0.00
23	Smith 2		195	(529)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
24									Oil-S	0	138,222	0	0		0.00
25	Smith 3		558	370,708	89.3	100.0	104.0	7,244	Gas-G	2,630,250	1,021	2,685,485	9,324,347	2.52	3.55
26	Smith A	(2)	36	27	0.1	98.9	129.8	53,963	Oil	251	138,219	1,457	26,317	97.47	104.85
27	Other Generation			5,169									186,432	3.61	0.00
28	Perdido			1,917					Landfill Gas				59,219	3.09	0.00
29	Daniel 1	(1)	255	(892)	0.0	100.0	0.0		Coal	0	0	0	0	0.00	0.00
30									Oil-S	0	138,382	0	0		0.00
31	Daniel 2	(1)	255	20,976	11.1	100.0	38.3	10,700	Coal	11,688	9,601	224,434	810,840	3.87	69.37
32									Oil-S	10	138,382	55	735		73.50
33	Total		2,385	516,767	29.1	88.3	47.2	8,432				4,297,755	15,522,272	3.00	

Notes & Adjust.: (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

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)	
(14,915)	Inventory Adjustment - Coal	(1,138,969)	
	Recoverable Fuel	14,379,281	2.78

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2015 Final True-Up Filing
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SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2015

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES:*								
2	UNITS (BBL)	0	567	(567)	(100.00)	13,645	7,986	5,659	70.86
3	UNIT COST ($/BBL)	0.00	84.43	(84.43)	(100.00)	77.37	107.15	(29.78)	(27.79)
4	AMOUNT ($)	0	47,869	(47,869)	(100.00)	1,055,755	855,700	200,055	23.38
5	*BURNED:*								
6	UNITS (BBL)	277	567	(290)	(51.15)	15,582	7,986	7,596	95.12
7	UNIT COST ($/BBL)	109.03	86.88	22.15	25.49	90.64	109.76	(19.12)	(17.42)
8	AMOUNT ($)	30,200	49,262	(19,062)	(38.70)	1,412,402	876,568	535,834	61.13
9	*ENDING INVENTORY:*								
10	UNITS (BBL)	5,061	4,998	63	1.26	5,061	4,998	63	1.26
11	UNIT COST ($/BBL)	90.96	96.43	(5.47)	(5.67)	90.96	96.43	(5.47)	(5.67)
12	AMOUNT ($)	460,338	481,936	(21,598)	(4.48)	460,338	481,936	(21,598)	(4.48)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES:*								
15	UNITS (TONS)	180,840	174,650	6,190	3.54	1,989,646	1,818,777	170,869	9.39
16	UNIT COST ($/TON)	71.76	75.17	(3.41)	(4.54)	80.80	78.23	2.57	3.29
17	AMOUNT ($)	12,977,416	13,128,783	(151,367)	(1.15)	160,763,787	142,286,944	18,476,843	12.99
18	*BURNED:*								
19	UNITS (TONS)	55,361	87,123	(31,762)	(36.46)	1,922,853	1,763,784	159,069	9.02
20	UNIT COST ($/TON)	80.10	74.57	5.53	7.42	82.89	80.26	2.63	3.28
21	AMOUNT ($)	4,434,597	6,496,947	(2,062,350)	(31.74)	159,379,572	141,568,429	17,811,143	12.58
22	*ENDING INVENTORY:*								
23	UNITS (TONS)	623,255	567,533	55,722	9.82	623,255	567,533	55,722	9.82
24	UNIT COST ($/TON)	75.11	79.17	(4.06)	(5.13)	75.11	79.17	(4.06)	(5.13)
25	AMOUNT ($)	46,809,590	44,934,213	1,875,377	4.17	46,809,590	44,934,213	1,875,377	4.17
26	DAYS SUPPLY	35	32	3	9.38				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES:*								
28	UNITS (MMBTU)	2,693,369	2,448,305	245,064	10.01	22,991,142	22,779,885	211,257	0.93
29	UNIT COST ($/MMBTU)	3.49	4.23	(0.74)	(17.49)	3.86	4.85	(0.99)	(20.41)
30	AMOUNT ($)	9,388,491	10,347,571	(959,080)	(9.27)	88,828,481	110,389,967	(21,561,486)	(19.53)
31	*BURNED:*								
32	UNITS (MMBTU)	2,693,369	2,448,305	245,064	10.01	23,394,547	22,779,885	614,662	2.70
33	UNIT COST ($/MMBTU)	3.58	4.23	(0.65)	(15.37)	3.89	4.85	(0.96)	(19.79)
34	AMOUNT ($)	9,647,206	10,347,571	(700,365)	(6.77)	90,942,376	110,389,967	(19,447,591)	(17.62)
35	*ENDING INVENTORY:*								
36	UNITS (MMBTU)	637,937	0	637,937	100.00	637,937	0	637,937	100.00
37	UNIT COST ($/MMBTU)	3.47	0.00	3.47	100.00	3.47	0.00	3.47	100.00
38	AMOUNT ($)	2,214,821	0	2,214,821	100.00	2,214,821	0	2,214,821	100.00
	OTHER - C.T. OIL								
39	*PURCHASES:*								
40	UNITS (BBL) *	355	0	355	100.00	2,132	0	2,132	100.00
41	UNIT COST ($/BBL)	61.84	0.00	61.84	100.00	73.55	0.00	74.00	100.00
42	AMOUNT ($)	21,952	0	21,952	100.00	156,819	0	156,819	100.00
43	*BURNED:*								
44	UNITS (BBL)	251	0	251	100.00	2,368	0	2,368	100.00
45	UNIT COST ($/BBL)	104.85	0.00	104.85	100.00	109.31	0.00	109.31	100.00
46	AMOUNT ($)	26,317	0	26,317	100.00	258,836	0	258,836	100.00
47	*ENDING INVENTORY:*								
48	UNITS (BBL)	6,821	7,677	(856)	(11.15)	6,821	7,677	(856)	(11.15)
49	UNIT COST ($/BBL)	104.82	104.61	0.21	0.20	104.82	104.61	0.21	0.20
50	AMOUNT ($)	715,009	803,101	(88,092)	(10.97)	715,009	803,101	(88,092)	(10.97)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2015

			CURRENT MONTH						
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	(a) c / KWH FUEL COST	(b) c / KWH TOTAL COST	(5) x (6)(a) TOTAL $ FOR FUEL ADJ.	(5) x (6)(b) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		201,023,000	0	201,023,000	2.13	2.41	4,290,000	4,841,000
2	Various	Economy Sales	9,958,000	0	9,958,000	2.27	2.54	226,000	253,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	34,001	34,000
4	TOTAL ESTIMATED SALES		210,981,000	0	210,981,000	2.16	2.43	4,550,001	5,128,000
	ACTUAL								
5	Southern Company Interchange		158,080,350	0	158,080,350	2.12	2.31	3,349,609	3,658,716
6	A.E.C.	External	255,735	0	255,735	2.36	2.98	6,043	7,615
7	AECI	External	0	0	0	0.00	0.00	0	0
8	BAM	External	0	0	0	0.00	0.00	0	0
9	CARGILE	External	387,773	0	387,773	1.95	3.04	7,565	11,775
10	DUKE PWR	External	0	0	0	0.00	0.00	0	0
11	EAGLE EN	External	167,320	0	167,320	1.85	2.71	3,098	4,538
12	ENDURE	External	2,653	0	2,653	2.52	4.20	67	111
13	EU	External	0	0	0	0.00	0.00	0	0
14	EXELON	External	730,063	0	730,063	1.70	2.72	12,425	19,886
15	FPC	External	64,334	0	64,334	1.57	3.29	1,010	2,118
16	FPL	External	162,289	0	162,289	2.79	3.84	4,524	6,233
17	JPMVEC	External	0	0	0	0.00	0.00	0	0
18	MISO	External	586,744	0	586,744	1.71	2.35	10,045	13,801
19	MORGAN	External	58,761	0	58,761	2.10	3.01	1,235	1,768
20	NCEMC	External	5,968	0	5,968	2.66	3.42	159	204
21	NCMPA1	External	0	0	0	0.00	0.00	0	0
22	NOBLEAGP	External	0	0	0	0.00	0.00	0	0
23	OPC	External	45,363	0	45,363	2.30	3.33	1,044	1,510
24	ORLANDO	External	4,974	0	4,974	2.81	4.50	140	224
25	PJM	External	343,681	0	343,681	2.01	3.22	6,903	11,064
26	SCE&G	External	1,759,544	0	1,759,544	2.39	3.21	42,053	56,473
27	SEC	External	74,744	0	74,744	2.27	3.28	1,699	2,453
28	SEPA	External	2,767,855	0	2,767,855	1.68	2.56	46,505	70,920
29	TAL	External	0	0	0	0.00	0.00	0	0
30	TEA	External	1,483,335	0	1,483,335	2.28	3.34	33,754	49,607
31	TECO	External	129,060	0	129,060	2.52	3.60	3,257	4,648
32	TENASKA	External	10,214	0	10,214	2.30	3.66	235	374
33	TVA	External	95,040	0	95,040	2.65	3.64	2,521	3,455
34	WRI	External	137,548	0	137,548	2.12	3.13	2,922	4,302
35	Less: Flow-Thru Energy		(7,963,374)	0	(7,963,374)	1.97	1.97	(156,880)	(156,880)
36	SEPA		869,264	869,264	0	0.00	0.00	0	0
37	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	44,466	44,466
38	Other transactions including adj.		161,597,032	143,623,315	17,973,717	0.00	0.00	0	0
39	TOTAL ACTUAL SALES		321,856,270	144,492,579	177,363,691	1.06	1.17	3,424,400	3,774,918
40	Difference in Amount		110,875,270	144,492,579	(33,617,309)	(1.10)	(1.26)	(1,125,601)	(1,353,082)
41	Difference in Percent		52.55	0.00	(15.93)	(50.93)	(51.85)	(24.74)	(26.39)

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 37

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2015

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) c / KWH FUEL COST	(6) (b) c / KWH TOTAL COST	(7) TOTAL $ FOR FUEL ADJ.	(8) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		1,525,278,000	0	1,525,278,000	2.90	3.19	44,282,000	48,661,000
2	Various	Economy Sales	87,277,000	0	87,277,000	2.98	3.23	2,601,000	2,821,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	436,001	436,000
4	TOTAL ESTIMATED SALES		1,612,555,000	0	1,612,555,000	2.93	3.22	47,319,001	51,918,000
	ACTUAL								
5	Southern Company Interchange		1,813,514,950	0	1,813,514,950	2.81	3.07	50,990,350	55,648,568
6	A.E.C.	External	27,664,917	0	27,664,917	2.38	2.92	657,967	806,553
7	AECI	External	401,439	0	401,439	2.37	2.99	9,528	11,994
8	BAM	External	5,903	0	5,903	2.00	3.27	118	193
9	CARGILE	External	1,666,301	0	1,666,301	2.75	3.23	45,815	53,890
10	DUKE PWR	External	2,417,202	0	2,417,202	2.41	4.44	58,314	107,228
11	EAGLE EN	External	2,635,516	0	2,635,516	2.50	3.69	65,784	97,252
12	ENDURE	External	115,729	0	115,729	2.70	4.50	3,129	5,203
13	EU	External	12,535	0	12,535	1.56	2.43	195	305
14	EXELON	External	3,577,787	0	3,577,787	2.40	3.10	85,796	111,074
15	FPC	External	418,822	0	418,822	2.16	3.24	9,028	13,555
16	FPL	External	2,534,321	0	2,534,321	2.68	4.32	68,032	109,386
17	JPMVEC	External	932,603	0	932,603	2.49	3.21	23,235	29,978
18	MISO	External	3,302,192	0	3,302,192	2.06	2.98	67,971	98,388
19	MORGAN	External	3,733,423	0	3,733,423	2.40	2.91	89,484	108,583
20	NCEMC	External	1,437,799	0	1,437,799	2.34	3.26	33,713	46,827
21	NCMPA1	External	2,321	0	2,321	2.34	3.57	54	83
22	NOBLEAGP	External	26,528	0	26,528	1.59	2.80	422	743
23	OPC	External	1,034,751	0	1,034,751	2.49	3.75	25,804	38,781
24	ORLANDO	External	622,504	0	622,504	3.19	4.93	19,861	30,712
25	PJM	External	9,851,304	0	9,851,304	2.30	3.69	227,006	363,534
26	SCE&G	External	8,894,603	0	8,894,603	2.67	3.33	237,722	296,126
27	SEC	External	297,914	0	297,914	2.45	3.24	7,304	9,641
28	SEPA	External	15,899,392	0	15,899,392	1.96	2.81	311,929	446,676
29	TAL	External	253,021	0	253,021	2.28	3.95	5,778	10,003
30	TEA	External	14,728,262	0	14,728,262	2.24	3.28	329,422	483,491
31	TECO	External	1,421,606	0	1,421,606	2.47	3.64	35,085	51,775
32	TENASKA	External	63,670	0	63,670	3.02	4.40	1,921	2,799
33	TVA	External	3,813,990	0	3,813,990	2.46	3.97	93,999	151,278
34	WRI	External	2,086,168	0	2,086,168	1.99	2.72	41,532	56,804
35	Less: Flow-Thru Energy		(101,999,950)	0	(101,999,950)	2.27	2.27	(2,315,499)	(2,315,499)
36	SEPA		10,939,368	10,939,368	0	0.00	0.00	0	0
37	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	616,337	616,337
38	Other transactions including adj.		1,927,693,082	1,578,602,956	349,090,126	0.00	0.00	0	0
39	TOTAL ACTUAL SALES		3,759,999,973	1,589,542,324	2,170,457,649	1.38	1.51	51,847,138	56,875,922
40	Difference in Amount		2,147,444,973	1,589,542,324	557,902,649	(1.55)	(1.71)	4,528,138	4,957,922
41	Difference in Percent		133.17	0.00	34.60	(52.90)	(53.11)	9.57	9.55

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 37

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: OCTOBER 2015

(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: OCTOBER 2015

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.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	5,114,000	0	0	0	3.52	3.52	179,915
3	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
4	Ascend Performance Materials	COG 1	12,890,000	0	0	0	2.43	2.43	313,025
5	International Paper	COG 1	12,000	0	0	0	2.31	2.31	277
6	TOTAL		18,016,000	0	0	0	2.74	2.74	493,218

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.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	44,117,000	0	0	0	3.53	3.53	1,558,087
3	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	62
4	Ascend Performance Materials	COG 1	120,256,000	0	0	0	2.70	2.70	3,244,439
5	International Paper	COG 1	842,000	0	0	0	2.83	2.83	23,802
6	TOTAL		165,215,000	0	0	0	2.92	2.92	4,826,390

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: OCTOBER 2015

		CURRENT MONTH			PERIOD - TO - DATE		
	(1) PURCHASED FROM	(2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	(5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	217,428,000	2.59	5,633,000	1,042,191,000	3.10	32,338,000
2	Economy Energy	5,161,000	2.65	137,000	41,703,000	3.31	1,381,000
3	Other Purchases	368,880,000	2.45	9,025,000	3,755,341,000	2.97	111,550,000
4	TOTAL ESTIMATED PURCHASES	591,469,000	2.50	14,795,000	4,839,235,000	3.00	145,269,000
	ACTUAL						
5	Southern Company Interchange	166,353,762	2.57	4,281,807	1,278,973,643	2.52	32,178,315
6	Non-Associated Companies	40,192,629	0.31	124,878	580,632,657	0.88	5,107,817
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	351,920,000	2.46	8,668,807	3,403,301,000	2.81	95,693,146
9	Other Wheeled Energy	35,218,000	0.00	N/A	511,037,000	0.00	N/A
10	Other Transactions	93,182,739	0.01	9,938	985,974,261	0.01	117,882
11	Less: Flow-Thru Energy	(7,963,374)	2.21	(176,311)	(101,999,950)	2.51	(2,557,938)
12	TOTAL ACTUAL PURCHASES	678,903,756	1.90	12,909,119	6,657,918,611	1.96	130,539,222
13	Difference in Amount	87,434,756	(0.60)	(1,885,881)	1,818,683,611	(1.04)	(14,729,778)
14	Difference in Percent	14.78	(24.00)	(12.75)	37.58	(34.67)	(10.14)

2015 CAPACITY CONTRACTS
GULF POWER COMPANY

	Capacity Costs ($)	CONTRACT	TERM		January	February	March	April	May	June	July	August	September	October	November	December	YTD
A.	CONTRACT/COUNTERPARTY	TYPE	Start	End													
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0	0	0	0	0	0	0	0	0	0			0
2	Power Purchase Agreements & Other Confidential Agreements				7,387,528	7,392,119	7,387,234	7,395,118	7,397,373	7,423,168	7,370,708	7,371,907	7,370,740	7,368,195			73,864,090
				Total	7,387,528	7,392,119	7,387,234	7,395,118	7,397,373	7,423,168	7,370,708	7,371,907	7370740	7368195			73,864,090

	Capacity Costs (MW)				January	February	March	April	May	June	July	August	September	October	November	December	YTD
B.	CONTRACT/COUNTERPARTY	TYPE	Start	End													
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0	0	0	0	0	0	0	0	0	0			0
2	Power Purchase Agreements & Other Confidential Agreements				Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies			

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 150001-EI

MONTHLY FUEL FILING

Novmeber 2015

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
NOVEMBER 2015

		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)	7,816,766	12,835,691	(5,018,925)	(39.10)	242,336,000	404,953,000	(162,617,000)	(40.16)	3.2256	3.1697	0.06	1.76
2	Hedging Settlement Costs (A2)	5,158,051	2,985,085	2,172,966	72.79	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	1,200	0	1,200	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	12,976,017	15,820,776	(2,844,759)	(17.98)	242,336,000	404,953,000	(162,617,000)	(40.16)	5.3546	3.9068	1.45	37.06
6	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
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	13,426,013	13,855,000	(428,987)	(3.10)	822,893,625	515,033,000	307,860,625	59.77	1.6316	2.6901	(1.06)	(39.35)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	522,344	0	522,344	100.00	21,750,000	0	21,750,000	100.00	2.4016	0.0000	2.40	0.00
12	TOTAL COST OF PURCHASED POWER	13,948,357	13,855,000	93,357	0.67	844,643,625	515,033,000	329,610,625	64.00	1.6514	2.6901	(1.04)	(38.61)
13	Total Available MWH (Line 5 + Line 12)	26,924,374	29,675,776	(2,751,402)	(9.27)	1,086,979,625	919,986,000	166,993,625	18.15				
14	Fuel Cost of Economy Sales (A6)	(139,728)	(243,000)	103,272	(42.50)	(7,185,029)	(11,704,000)	4,518,971	(38.61)	(1.9447)	(2.0762)	0.13	6.33
15	Gain on Economy Sales (A6)	(25,558)	(20,800)	(4,758)	22.88	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(449,855)	(1,581,000)	1,131,145	(71.55)	(261,833,170)	(77,890,000)	(183,943,170)	236.16	(0.1718)	(2.0298)	1.86	91.54
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(615,142)	(1,844,800)	1,229,659	(66.66)	(269,018,199)	(89,594,000)	(179,424,199)	200.26	(0.2287)	(2.0591)	1.83	88.89
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	26,309,233	27,830,976	(1,521,744)	(5.47)	817,961,426	830,392,000	(12,430,574)	(1.50)	3.2164	3.3515	(0.14)	(4.03)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	61,248	52,384	8,864	16.92	1,904,242	1,563,000	341,242	21.83	3.2164	3.3515	(0.14)	(4.03)
22	T & D Losses *	1,382,110	1,172,891	209,219	17.84	42,970,713	34,996,000	7,974,713	22.79	3.2164	3.3515	(0.14)	(4.03)
23	TERRITORIAL KWH SALES	26,309,232	27,830,976	(1,521,744)	(5.47)	773,086,471	793,833,000	(20,746,529)	(2.61)	3.4031	3.5059	(0.10)	(2.93)
24	Wholesale KWH Sales	758,654	808,379	(49,725)	(6.15)	22,292,503	23,058,000	(765,497)	(3.32)	3.4032	3.5059	(0.10)	(2.93)
25	Jurisdictional KWH Sales	25,550,578	27,022,597	(1,472,019)	(5.45)	750,793,968	770,775,000	(19,981,032)	(2.59)	3.4031	3.5059	(0.10)	(2.93)
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	25,588,904	27,063,131	(1,474,227)	(5.45)	750,793,968	770,775,000	(19,981,032)	(2.59)	3.4082	3.5112	(0.10)	(2.93)
28	TRUE-UP	3,996,375	3,996,375	0	0.00	750,793,968	770,775,000	(19,981,032)	(2.59)	0.5323	0.5185	0.01	2.66
29	TOTAL JURISDICTIONAL FUEL COST	29,585,279	31,059,506	(1,474,227)	(4.75)	750,793,968	770,775,000	(19,981,032)	(2.59)	3.9405	4.0297	(0.09)	(2.21)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.9433	4.0326	(0.09)	(2.21)
32	GPIF Reward / (Penalty)	210,328	210,328	0	0.00	750,793,968	770,775,000	(19,981,032)	(2.59)	0.0280	0.0273	0.00	2.56
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.9713	4.0599	(0.09)	(2.18)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.971	4.060		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: NOVEMBER 2015

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 7,816,766
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	1,200
4	Hedging Settlement Costs	Schedule A-2, Line A-5	5,158,051
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	13,426,013
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	522,344
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(615,142)
10	Total Fuel and Net Power Transactions		$ 26,309,232

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
NOVEMBER 2015
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)	262,556,909	268,859,504	(6,302,595)	(2.34)	7,512,488,000	7,423,187,000	89,301,000	1.20	3.4949	3.6219	(0.13)	(3.51)
2	Hedging Settlement Costs (A2)	44,338,263	17,916,910	26,421,353	147.47	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	(102,102)	0	(102,102)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	306,793,070	286,776,414	20,016,656	6.98	7,512,488,000	7,423,187,000	89,301,000	1.20	4.0838	3.8633	0.22	5.71
6	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
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0.00	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	143,965,235	159,124,000	(15,158,765)	(9.53)	7,480,812,236	5,354,268,000	2,126,544,236	39.72	1.9245	2.9719	(1.05)	(35.24)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	5,348,734	0	5,348,734	100.00	186,965,000	0	186,965,000	100.00	2.8608	0.0000	2.86	0.00
12	TOTAL COST OF PURCHASED POWER	149,313,969	159,124,000	(9,810,031)	(6.17)	7,667,777,236	5,354,268,000	2,313,509,236	43.21	1.9473	2.9719	(1.02)	(34.48)
13	Total Available MWH (Line 5 + Line 12)	456,107,039	445,900,414	10,206,625	2.29	15,180,265,236	12,777,455,000	2,402,810,236	18.81				
14	Fuel Cost of Economy Sales (A6)	(2,695,676)	(2,844,000)	148,324	(5.22)	(117,037,552)	(98,981,000)	(18,056,552)	18.24	(2.3033)	(2.8733)	0.57	19.84
15	Gain on Economy Sales (A6)	(641,895)	(456,801)	(185,094)	40.52	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(49,124,707)	(45,863,000)	(3,261,707)	7.11	(3,911,980,620)	(1,603,168,000)	(2,308,812,620)	144.02	(1.2558)	(2.8608)	1.61	56.10
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(52,462,279.87)	(49,163,801)	(3,298,478)	6.71	(4,029,018,172)	(1,702,149,000)	(2,326,869,172)	136.70	(1.3021)	(2.8883)	1.59	54.92
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	403,644,759	396,736,613	6,908,146	1.74	11,151,247,064	11,075,306,000	75,941,064	0.69	3.6197	3.5822	0.04	1.05
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	781,959	686,468	95,491	13.91	21,602,860	19,163,300	2,439,560	12.73	3.6197	3.5822	0.04	1.05
22	T & D Losses *	18,630,734	21,394,822	(2,764,088)	(12.92)	514,703,808	597,253,700	(82,549,892)	(13.82)	3.6197	3.5822	0.04	1.05
23	TERRITORIAL KWH SALES	403,644,759	396,736,613	6,908,146	1.74	10,614,940,396	10,458,889,000	156,051,396	1.49	3.8026	3.7933	0.01	0.25
24	Wholesale KWH Sales	11,076,370	11,819,336	(742,966)	(6.29)	291,150,932	310,106,000	(18,955,068)	(6.11)	3.8043	3.8114	(0.01)	(0.19)
25	Jurisdictional KWH Sales	392,568,389	384,917,277	7,651,112	1.99	10,323,789,464	10,148,783,000	175,006,464	1.72	3.8026	3.7927	0.01	0.26
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	393,157,241	385,494,653	7,662,588	1.99	10,323,789,464	10,148,783,000	175,006,464	1.72	3.8083	3.7984	0.01	0.26
28	TRUE-UP	43,960,120	43,960,120	0	0.00	10,323,789,464	10,148,783,000	175,006,464	1.72	0.4258	0.4332	(0.01)	(1.71)
29	TOTAL JURISDICTIONAL FUEL COST	437,117,361	429,454,773	7,662,588	1.78	10,323,789,464	10,148,783,000	175,006,464	1.72	4.2341	4.2316	0.00	0.06
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.2371	4.2346	0.00	0.06
32	GPIF Reward / (Penalty)	2,313,610	2,313,610	0	0.00	10,323,789,464	10,148,783,000	175,006,464	1.72	0.0224	0.0228	(0.00)	(1.75)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.2595	4.2574	0.00	0.05
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.260	4.257		

* 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: NOVEMBER 2015

		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	7,661,580.70	12,638,222	(4,976,641.30)	(39.38)	260,264,440.23	266,128,182	(5,863,741.77)	(2.20)
1a	Other Generation	155,184.89	197,469	(42,284.11)	(21.41)	2,292,468.50	2,731,322	(438,853.50)	(16.07)
2	Fuel Cost of Power Sold	(615,141.85)	(1,844,800)	1,229,658.15	66.66	(52,462,280.34)	(49,163,801)	(3,298,479.34)	(6.71)
3	Fuel Cost - Purchased Power	13,426,012.81	13,855,000	(428,987.19)	(3.10)	143,965,235.15	159,124,000	(15,158,764.85)	(9.53)
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	522,344.01	0	522,344.01	100.00	5,348,734.36	0	5,348,734.36	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	5,158,051.00	2,985,085	2,172,966.00	72.79	44,338,263.43	17,916,910	26,421,353.43	147.47
6	Total Fuel & Net Power Transactions	26,308,031.56	27,830,976	(1,522,944.44)	(5.47)	403,746,861.34	396,736,613	7,010,248.33	1.77
7	AdjustmentsTo Fuel Cost*	1,200.00	0	1,200.00	100.00	(102,101.62)	0	(102,101.62)	100.00
8	Adj. Total Fuel & Net Power Transactions	26,309,231.56	27,830,976	(1,521,744.44)	(5.47)	403,644,759.72	396,736,613	6,908,146.72	1.74
B.	*KWH Sales*								
1	Jurisdictional Sales	750,793,968	770,775,000	(19,981,032)	(2.59)	10,323,789,464	10,148,783,000	175,006,464	1.72
2	Non-Jurisdictional Sales	22,292,503	23,058,000	(765,497)	(3.32)	291,150,932	310,106,000	(18,955,068)	(6.11)
3	Total Territorial Sales	773,086,471	793,833,000	(20,746,529)	(2.61)	10,614,940,396	10,458,889,000	156,051,396	1.49
4	Juris. Sales as % of Total Terr. Sales	97.1164	97.0954	0.0210	0.02	97.2572	97.0350	0.2222	0.23

**(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: NOVEMBER 2015

		CURRENT MONTH				PERIOD - TO - DATE			
		$		*DIFFERENCE*		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	31,727,591.49	33,390,597	(1,663,005.08)	(4.98)	446,761,995.26	439,653,490	7,108,505.16	1.62
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(3,996,375.00)	(3,996,375)	0.00	0.00	(43,960,120.00)	(43,960,120)	0.00	0.00
2b	Incentive Provision	(210,177.00)	(210,177)	0.00	0.00	(2,311,945.00)	(2,311,945)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	27,521,039.49	29,184,045	(1,663,005.51)	(5.70)	400,489,930.26	393,381,425	7,108,505.26	1.81
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	26,309,231.56	27,830,976	(1,521,744.44)	(5.47)	403,644,759.99	396,736,613	6,908,146.99	1.74
5	Juris. Sales % of Total KWH Sales (Line B4)	97.1164	97.0954	0.0210	0.02	97.2572	97.0350	0.2222	0.23
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	25,588,904.43	27,063,131	(1,474,226.57)	(5.45)	393,157,241.20	385,494,653	7,662,588.20	1.99
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	1,932,135.06	2,120,914	(188,778.94)	8.90	7,332,689.06	47,850,512	(40,517,822.94)	84.68
8	Interest Provision for the Month	952.79	91	861.79	(947.02)	(17,201.47)	(25,683)	8,481.53	33.02
9	Beginning True-Up & Interest Provision	5,467,532.06	(2,252,666)	7,720,198.06	342.71	(39,871,741.42)	(47,956,495)	8,084,753.58	16.86
10	True-Up Collected / (Refunded)	3,996,375.00	3,996,375	0.00	0.00	43,960,120.00	3,996,380	39,963,740.00	1,000.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	11,396,994.91	3,864,714	7,532,280.91	(194.90)	11,403,866.17	3,864,714	7,539,152.17	(195.08)
12	Adjustment	0.00	0	0.00	0.00	(6,871.26)	0	(6,871.26)	100.00
13	End of Period - Total Net True-Up	11,396,994.91	3,864,714	7,532,280.91	(194.90)	11,396,994.91	3,864,714	7,532,280.91	(194.90)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2015

		CURRENT MONTH			
		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	5,467,532.06	(2,252,666)	7,720,198.06	(342.71)
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	11,396,042.12	3,864,623	7,531,419.12	194.88
3	Total of Beginning & Ending True-Up Amts.	16,863,574.18	1,611,957	15,251,617.18	946.16
4	Average True-Up Amount	8,431,787.09	805,979	7,625,808.09	946.15
	Interest Rate				
5	1st Day of Reporting Business Month	0.12	0.12	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.15	0.15	0.0000	
7	Total (D5+D6)	0.27	0.27	0.0000	
8	Annual Average Interest Rate	0.14	0.14	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0113	0.0113	0.0000	
10	Interest Provision (D4*D9)	952.79	91	861.79	947.02
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0015		

Docket No. 160001-EI
2015 Final True-Up Filing
Exhibit CSB-1, Page 177 of 202

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2015

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	80,565	59,554	21,011	35.28	1,437,296	936,122	501,174	53.54
2	COAL	3,261,631	5,938,956	(2,677,325)	(45.08)	162,680,407	147,507,385	15,173,022	10.29
3	GAS	4,104,897	6,501,642	(2,396,745)	(36.86)	95,257,621	117,149,873	(21,892,252)	(18.69)
4	GAS (B.L.)	302,532	273,411	29,121	10.65	2,236,967	2,549,000	(312,033)	(12.24)
5	LANDFILL GAS	67,141	62,128	5,013	8.07	685,779	717,124	(31,345)	(4.37)
6	OIL - C.T.	0	0	0	0.00	258,837	0	258,837	100.00
7	TOTAL ($)	7,816,766	12,835,691	(5,018,925)	(39.10)	262,556,909	268,859,504	(6,302,595)	(2.34)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	70,365	174,023	(103,658)	(59.57)	4,072,217	3,869,163	203,054	5.25
10	GAS	169,801	228,899	(59,098)	(25.82)	3,417,206	3,530,390	(113,184)	(3.21)
11	LANDFILL GAS	2,179	2,031	148	7.29	22,298	23,634	(1,336)	(5.65)
12	OIL - C.T.	(9)	0	(9)	100.00	767	0	767	100.00
13	TOTAL (MWH)	242,336	404,953	(162,617)	(40.16)	7,512,488	7,423,187	89,301	1.20
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	921	664	257	38.70	15,898	8,650	7,248	83.79
15	COAL (TONS)	44,238	87,354	(43,116)	(49.36)	1,967,091	1,851,138	115,953	6.26
16	GAS (MCF) (1)	1,187,393	1,576,835	(389,442)	(24.70)	22,814,124	24,080,443	(1,266,319)	(5.26)
17	OIL - C.T. (BBL)	0	0	0	0.00	2,368	0	2,368	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	900,221	1,864,659	(964,438)	(51.72)	44,770,858	41,187,048	3,583,810	8.70
19	GAS - Generation (1)	1,204,277	1,593,371	(389,094)	(24.42)	23,235,624	24,238,256	(1,002,632)	(4.14)
20	OIL - C.T.	0	0	0	0.00	13,796	0	13,796	100.00
21	TOTAL (MMBTU)	2,104,498	3,458,030	(1,353,532)	(39.14)	68,020,278	65,425,304	2,594,974	3.97
	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	29.03	42.98	(13.95)	(32.46)	54.20	52.12	2.08	3.99
24	GAS	70.07	56.52	13.55	23.97	45.49	47.56	(2.07)	(4.35)
25	LANDFILL GAS	0.90	0.50	0.40	80.00	0.30	0.32	(0.02)	(6.25)
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)	87.43	89.69	(2.26)	(2.52)	90.41	108.22	(17.81)	(16.46)
29	COAL ($/TON)	73.73	67.99	5.74	8.44	82.70	79.68	3.02	3.79
30	GAS ($/MCF) (1)	3.58	4.17	(0.59)	(14.15)	4.17	4.86	(0.69)	(14.20)
31	OIL - C.T. ($/BBL)	0.00	0.00	0.00	0.00	109.31	0.00	109.31	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.05	3.36	0.69	20.54	3.72	3.67	0.05	1.36
33	GAS - Generation (1)	3.28	3.96	(0.68)	(17.17)	4.00	4.72	(0.72)	(15.25)
34	OIL - C.T.	0.00	0.00	0.00	0.00	18.76	0.00	18.76	100.00
35	TOTAL ($/MMBTU)	3.61	3.64	(0.03)	(0.82)	3.82	4.06	(0.24)	(5.91)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	12,794	10,715	2,079	19.40	10,994	10,645	349	3.28
37	GAS - Generation (1)	7,264	7,134	130	1.82	6,927	7,016	(89)	(1.27)
38	OIL - C.T.	0	0	0	0.00	17,987	0	17,987	100.00
39	TOTAL (BTU/KWH)	8,912	8,702	210	2.41	9,158	8,933	225	2.52
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	5.18	3.60	1.58	43.89	4.09	3.90	0.19	4.87
41	GAS	2.42	2.84	(0.42)	(14.79)	2.79	3.32	(0.53)	(15.96)
42	LANDFILL GAS	3.08	3.06	0.02	0.65	3.08	3.03	0.05	1.65
43	OIL - C.T.	0.00	0.00	0.00	0.00	33.75	0.00	33.75	100.00
44	TOTAL (¢/KWH)	3.23	3.17	0.06	1.89	3.49	3.62	(0.13)	(3.59)

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: NOVEMBER 2015

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2015	(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	(1,013)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
2				0					Gas-G	0	1,021	0	0	0.00	0.00
3									Gas-S	0	1,021	0	0		0.00
4									Oil-S	0	138,131	0	0		0.00
5	Crist 5		75	(1,011)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
6				0					Gas-G	0	1,021	0	0	0.00	0.00
7									Gas-S	0	1,021	0	0		0.00
8									Oil-S	0	138,131	0	0		0.00
9	Crist 6		299	(1,527)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
10				0					Gas-G	0	1,021	0	0	0.00	0.00
11									Gas-S	0	1,021	0	0		0.00
12									Oil-S	0	138,131	0	0		0.00
13	Crist 7		475	38,527	11.2	84.8	47.5	11,293	Coal	19,527	11,141	435,101	1,631,191	4.23	83.54
14				0					Gas-G	0	1,021	0	0	0.00	0.00
15									Gas-S	9,040	1,021	9,230	302,532		33.47
16									Oil-S	262	138,131	1,519	29,564		112.84
17	Scholz 1		0	0	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	0	0	0		0.00
19	Scholz 2		0	0	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	0	0	0		0.00
21	Smith 1		162	(562)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
22									Oil-S	0	138,222	0	0		0.00
23	Smith 2		195	(596)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
24									Oil-S	0	138,222	0	0		0.00
25	Smith 3		558	165,788	41.2	58.4	88.0	7,264	Gas-G	1,178,353	1,022	1,204,276	3,949,712	2.38	3.35
26	Smith A	(2)	36	(9)	0.0	100.0	0.0	0	Oil	0	138,539	0	0	0.00	0.00
27	Other Generation			4,013									155,185	3.87	0.00
28	Perdido			2,179					Landfill Gas				67,141	3.08	0.00
29	Daniel 1	(1)	255	28,674	15.6	100.0	35.3	11,972	Coal	18,698	9,180	343,275	1,236,736	4.31	66.14
30									Oil-S	380	138,839	2,221	29,456		77.52
31	Daniel 2	(1)	255	7,873	4.3	100.0	27.0	13,623	Coal	6,013	8,918	107,251	397,726	5.05	66.14
32									Oil-S	279	138,839	1,625	21,545		77.22
33	Total		2,385	242,336	14.1	87.2	36.7	8,912				2,104,498	7,820,788	3.23	

Notes & Adjust.: (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

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)	
	Recoverable Fuel	7,816,766	3.23

Docket No. 160001-EI
2015 Final True-Up Filing
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SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2015

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES :*								
2	UNITS (BBL)	0	664	(664)	(100.00)	13,645	8,650	4,995	57.75
3	UNIT COST ($/BBL)	0.00	84.45	(84.45)	(100.00)	77.37	105.41	(28.04)	(26.60)
4	AMOUNT ($)	0	56,072	(56,072)	(100.00)	1,055,755	911,772	143,983	15.79
5	*BURNED :*								
6	UNITS (BBL)	951	664	287	43.22	16,533	8,650	7,883	91.13
7	UNIT COST ($/BBL)	87.04	89.69	(2.65)	(2.95)	90.44	108.22	(17.78)	(16.43)
8	AMOUNT ($)	82,773	59,554	23,219	38.99	1,495,175	936,122	559,053	59.72
9	*ENDING INVENTORY :*								
10	UNITS (BBL)	4,110	4,998	(888)	(17.77)	4,110	4,998	(888)	(17.77)
11	UNIT COST ($/BBL)	91.86	95.73	(3.87)	(4.04)	91.86	95.73	(3.87)	(4.04)
12	AMOUNT ($)	377,565	478,454	(100,889)	(21.09)	377,565	478,454	(100,889)	(21.09)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES :*								
15	UNITS (TONS)	86,452	113,250	(26,798)	(23.66)	2,076,098	1,932,027	144,071	7.46
16	UNIT COST ($/TON)	65.90	68.66	(2.76)	(4.02)	80.18	77.67	2.51	3.23
17	AMOUNT ($)	5,697,525	7,775,939	(2,078,414)	(26.73)	166,461,312	150,062,883	16,398,429	10.93
18	*BURNED :*								
19	UNITS (TONS)	44,238	87,354	(43,116)	(49.36)	1,967,091	1,851,138	115,953	6.26
20	UNIT COST ($/TON)	73.82	67.99	5.83	8.57	82.68	79.68	3.00	3.77
21	AMOUNT ($)	3,265,653	5,938,956	(2,673,303)	(45.01)	162,645,225	147,507,385	15,137,840	10.26
22	*ENDING INVENTORY :*								
23	UNITS (TONS)	665,470	593,429	72,041	12.14	665,470	593,429	72,041	12.14
24	UNIT COST ($/TON)	74.00	78.82	(4.82)	(6.12)	74.00	78.82	(4.82)	(6.12)
25	AMOUNT ($)	49,241,462	46,771,196	2,470,266	5.28	49,241,462	46,771,196	2,470,266	5.28
26	DAYS SUPPLY	38	34	4	11.76				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES :*								
28	UNITS (MMBTU)	1,202,284	1,608,371	(406,087)	(25.25)	24,193,426	24,388,256	(194,830)	(0.80)
29	UNIT COST ($/MMBTU)	3.40	4.09	(0.69)	(16.87)	3.84	4.80	(0.96)	(20.00)
30	AMOUNT ($)	4,092,396	6,577,584	(2,485,188)	(37.78)	92,920,877	116,967,551	(24,046,674)	(20.56)
31	*BURNED :*								
32	UNITS (MMBTU)	1,213,507	1,608,371	(394,864)	(24.55)	24,608,054	24,388,256	219,798	0.90
33	UNIT COST ($/MMBTU)	3.50	4.09	(0.59)	(14.43)	3.87	4.80	(0.93)	(19.38)
34	AMOUNT ($)	4,251,925	6,577,584	(2,325,659)	(35.36)	95,194,301	116,967,551	(21,773,250)	(18.61)
35	*ENDING INVENTORY :*								
36	UNITS (MMBTU)	626,714	0	626,714	100.00	626,714	0	626,714	100.00
37	UNIT COST ($/MMBTU)	3.28	0.00	3.28	100.00	3.28	0.00	3.28	100.00
38	AMOUNT ($)	2,055,291	0	2,055,291	100.00	2,055,291	0	2,055,291	100.00
	OTHER - C.T. OIL								
39	*PURCHASES :*								
40	UNITS (BBL) *	0	0	0	0.00	2,132	0	2,132	100.00
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	73.55	0.00	74.00	100.00
42	AMOUNT ($)	0	0	0	0.00	156,819	0	156,819	100.00
43	*BURNED :*								
44	UNITS (BBL)	0	0	0	0.00	2,368	0	2,368	100.00
45	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	109.31	0.00	109.31	100.00
46	AMOUNT ($)	0	0	0	0.00	258,836	0	258,836	100.00
47	*ENDING INVENTORY :*								
48	UNITS (BBL)	6,821	7,677	(856)	(11.15)	6,821	7,677	(856)	(11.15)
49	UNIT COST ($/BBL)	104.82	104.61	0.21	0.20	104.82	104.61	0.21	0.20
50	AMOUNT ($)	715,009	803,101	(88,092)	(10.97)	715,009	803,101	(88,092)	(10.97)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
Page 1 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2015

	(1) SOLD TO	(2) TYPE AND SCHEDULE	(3) TOTAL KWH SOLD	(4) KWH WHEELED FROM OTHER SYSTEMS	(5) KWH FROM OWN GENERATION	(6) (a) FUEL COST c / KWH	(6) (b) TOTAL COST c / KWH	(7) (5) x (6)(a) TOTAL $ FOR FUEL ADJ.	(8) (5) x (6)(b) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		77,890,000	0	77,890,000	2.03	2.32	1,581,000	1,807,000
2	Various	Economy Sales	11,704,000	0	11,704,000	2.08	2.38	243,000	278,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	20,800	26,000
4	TOTAL ESTIMATED SALES		89,594,000	0	89,594,000	2.06	2.36	1,844,800	2,111,000
	ACTUAL								
5	Southern Company Interchange		31,705,904	0	31,705,904	1.73	1.52	548,707	482,530
6	A.E.C.	External	250,692	0	250,692	1.69	2.58	4,245	6,461
7	AECI	External	0	0	0	0.00	0.00	0	0
8	BAM	External	0	0	0	0.00	0.00	0	0
9	CARGILE	External	283,060	0	283,060	2.10	3.37	5,933	9,540
10	DUKE PWR	External	0	0	0	0.00	0.00	0	0
11	EAGLE EN	External	60,351	0	60,351	5.38	3.09	3,248	1,865
12	ENDURE	External	0	0	0	0.00	0.00	0	0
13	EU	External	0	0	0	0.00	0.00	0	0
14	EXELON	External	52,525	0	52,525	1.71	2.48	897	1,301
15	FPC	External	250,167	0	250,167	2.67	6.66	6,676	16,657
16	FPL	External	258,783	0	258,783	2.42	3.51	6,261	9,076
17	JPMVEC	External	0	0	0	0.00	0.00	0	0
18	MISO	External	682,455	0	682,455	1.39	2.04	9,508	13,893
19	MORGAN	External	44,503	0	44,503	1.71	2.45	761	1,090
20	NCEMC	External	382,528	0	382,528	1.73	2.25	6,607	8,611
21	NCMPA1	External	3,979	0	3,979	70.73	2.10	2,814	84
22	NOBLEAGP	External	0	0	0	0.00	0.00	0	0
23	OPC	External	26,197	0	26,197	1.35	1.96	355	514
24	ORLANDO	External	0	0	0	0.00	0.00	0	0
25	PJM	External	187,486	0	187,486	1.73	2.88	3,241	5,406
26	SCE&G	External	2,517,948	0	2,517,948	1.80	2.38	45,209	60,040
27	SEC	External	30,507	0	30,507	1.44	2.48	439	757
28	SEPA	External	103,994	0	103,994	2.50	5.62	2,602	5,849
29	TAL	External	3,316	0	3,316	1.82	2.80	60	93
30	TEA	External	995,237	0	995,237	1.73	2.65	17,214	26,399
31	TECO	External	519,823	0	519,823	2.66	3.93	13,842	20,436
32	TENASKA	External	0	0	0	0.00	0.00	0	0
33	TVA	External	354,832	0	354,832	1.89	3.23	6,706	11,444
34	WRI	External	176,646	0	176,646	1.76	2.28	3,108	4,027
35	Less: Flow-Thru Energy		(5,150,095)	0	(5,150,095)	1.92	1.92	(98,852)	(98,852)
36	SEPA		2,350,304	2,350,304	0	0.00	0.00	0	0
37	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	25,558	25,558
38	Other transactions including adj.		232,927,057	136,261,927	96,665,130	0.00	0.00	0	0
39	TOTAL ACTUAL SALES		269,018,199	138,612,231	130,405,968	0.23	0.22	615,142	587,221
40	Difference in Amount		179,424,199	138,612,231	40,811,968	(1.83)	(2.14)	(1,229,659)	(1,523,779)
41	Difference in Percent		200.26	0.00	45.55	(88.83)	(90.68)	(66.66)	(72.18)

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 37

SCHEDULE A6
Page 2 of 2

POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2015

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) FUEL COST c / KWH	(6) (b) TOTAL COST c / KWH	(7) TOTAL $ FOR FUEL ADJ.	(8) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		1,603,168,000	0	1,603,168,000	2.86	3.15	45,863,000	50,468,000
2	Various	Economy Sales	98,981,000	0	98,981,000	2.87	3.13	2,844,000	3,099,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	456,801	462,000
4	TOTAL ESTIMATED SALES		1,702,149,000	0	1,702,149,000	2.89	3.17	49,163,801	54,029,000
	ACTUAL								
5	Southern Company Interchange		1,845,220,854	0	1,845,220,854	2.79	3.04	51,539,057	56,131,098
6	A.E.C.	External	27,915,609	0	27,915,609	2.37	2.91	662,212	813,014
7	AECI	External	401,439	0	401,439	2.37	2.99	9,528	11,994
8	BAM	External	5,903	0	5,903	2.00	3.27	118	193
9	CARGILE	External	1,949,361	0	1,949,361	2.65	3.25	51,748	63,430
10	DUKE PWR	External	2,417,202	0	2,417,202	2.41	4.44	58,314	107,228
11	EAGLE EN	External	2,695,867	0	2,695,867	2.56	3.68	69,033	99,117
12	ENDURE	External	115,729	0	115,729	2.70	4.50	3,129	5,203
13	EU	External	12,535	0	12,535	1.56	2.43	195	305
14	EXELON	External	3,630,312	0	3,630,312	2.39	3.10	86,693	112,375
15	FPC	External	668,989	0	668,989	2.35	4.52	15,704	30,212
16	FPL	External	2,793,104	0	2,793,104	2.66	4.24	74,293	118,461
17	JPMVEC	External	932,603	0	932,603	2.49	3.21	23,235	29,978
18	MISO	External	3,984,647	0	3,984,647	1.94	2.82	77,479	112,281
19	MORGAN	External	3,777,926	0	3,777,926	2.39	2.90	90,245	109,674
20	NCEMC	External	1,820,327	0	1,820,327	2.22	3.05	40,321	55,439
21	NCMPA1	External	6,300	0	6,300	45.53	2.64	2,868	166
22	NOBLEAGP	External	26,528	0	26,528	1.59	2.80	422	743
23	OPC	External	1,060,948	0	1,060,948	2.47	3.70	26,159	39,295
24	ORLANDO	External	622,504	0	622,504	3.19	4.93	19,861	30,712
25	PJM	External	10,038,790	0	10,038,790	2.29	3.68	230,247	368,940
26	SCE&G	External	11,412,551	0	11,412,551	2.48	3.12	282,931	356,166
27	SEC	External	328,421	0	328,421	2.36	3.17	7,743	10,398
28	SEPA	External	16,003,386	0	16,003,386	1.97	2.83	314,531	452,525
29	TAL	External	256,337	0	256,337	2.28	3.94	5,839	10,096
30	TEA	External	15,723,499	0	15,723,499	2.20	3.24	346,636	509,890
31	TECO	External	1,941,429	0	1,941,429	2.52	3.72	48,927	72,211
32	TENASKA	External	63,670	0	63,670	3.02	4.40	1,921	2,799
33	TVA	External	4,168,822	0	4,168,822	2.42	3.90	100,705	162,722
34	WRI	External	2,262,814	0	2,262,814	1.97	2.69	44,640	60,831
35	Less: Flow-Thru Energy		(107,150,045)	0	(107,150,045)	2.25	2.25	(2,414,351)	(2,414,351)
36	SEPA		13,289,672	13,289,672	0	0.00	0.00	0	0
37	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	641,895	641,895
38	Other transactions including adj.		2,160,620,139	1,714,864,883	445,755,256	0.00	0.00	0	0
39	TOTAL ACTUAL SALES		4,029,018,172	1,728,154,555	2,300,863,617	1.30	1.43	52,462,280	57,463,143
40	Difference in Amount		2,326,869,172	1,728,154,555	598,714,617	(1.59)	(1.74)	3,298,479	3,434,143
41	Difference in Percent		136.70	0.00	35.17	(55.02)	(54.89)	6.71	6.36

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 37

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: NOVEMBER 2015

(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: NOVEMBER 2015

CURRENT MONTH

(1) PURCHASED FROM:	(2) TYPE AND SCHEDULE	(3) TOTAL KWH PURCHASED	(4) KWH FOR OTHER UTILITIES	(5) KWH FOR INTERRUPTIBLE	(6) KWH FOR FIRM	(7) ¢/KWH (A) FUEL COST	(7) ¢/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ.
ESTIMATED								
1		0	0	0	0	0.00	0.00	0
ACTUAL								
2 Bay County/Engen, LLC	Contract	5,220,000	0	0	0	3.52	3.52	183,648
3 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	0
4 Ascend Performance Materials	COG 1	16,526,000	0	0	0	2.05	2.05	338,620
5 International Paper	COG 1	4,000	0	0	0	1.92	1.92	77
6 TOTAL		21,750,000	0	0	0	2.40	2.40	522,344

PERIOD-TO-DATE

(1) PURCHASED FROM:	(2) TYPE AND SCHEDULE	(3) TOTAL KWH PURCHASED	(4) KWH FOR OTHER UTILITIES	(5) KWH FOR INTERRUPTIBLE	(6) KWH FOR FIRM	(7) ¢/KWH (A) FUEL COST	(7) ¢/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ.
ESTIMATED								
1		0	0	0	0	0.00	0.00	0
ACTUAL								
2 Bay County/Engen, LLC	Contract	49,337,000	0	0	0	3.53	3.53	1,741,734
3 Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	62
4 Ascend Performance Materials	COG 1	136,782,000	0	0	0	2.62	2.62	3,583,059
5 International Paper	COG 1	846,000	0	0	0	2.82	2.82	23,879
6 TOTAL		186,965,000	0	0	0	2.86	2.86	5,348,734

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: NOVEMBER 2015

	(1)	CURRENT MONTH (2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	PERIOD - TO - DATE (5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	PURCHASED FROM						
	ESTIMATED						
1	Southern Company Interchange	296,833,000	2.36	7,004,000	1,339,024,000	2.94	39,342,000
2	Economy Energy	5,414,000	2.36	128,000	47,117,000	3.20	1,509,000
3	Other Purchases	212,786,000	3.16	6,723,000	3,968,127,000	2.98	118,273,000
4	TOTAL ESTIMATED PURCHASES	515,033,000	2.69	13,855,000	5,354,268,000	2.97	159,124,000
	ACTUAL						
5	Southern Company Interchange	299,034,994	2.20	6,580,456	1,578,008,637	2.46	38,758,772
6	Non-Associated Companies	41,417,367	0.65	269,039	622,050,024	0.86	5,376,856
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	281,455,000	2.37	6,666,632	3,684,756,000	2.78	102,359,778
9	Other Wheeled Energy	107,066,000	0.00	N/A	618,103,000	0.00	N/A
10	Other Transactions	99,070,359	0.02	19,452	1,085,044,620	0.01	137,334
11	Less: Flow-Thru Energy	(5,150,095)	2.13	(109,567)	(107,150,045)	2.49	(2,667,505)
12	TOTAL ACTUAL PURCHASES	822,893,625	1.63	13,426,012.62	7,480,812,236	1.92	143,965,236
13	Difference in Amount	307,860,625	(1.06)	(428,987)	2,126,544,236	(1.05)	(15,158,764)
14	Difference in Percent	59.77	(39.41)	(3.10)	39.72	(35.35)	(9.53)

2015 CAPACITY CONTRACTS
GULF POWER COMPANY

	Capacity Costs ($)	CONTRACT	TERM		January	February	March	April	May	June	July	August	September	October	November	December	YTD
A.	CONTRACT/COUNTERPARTY	TYPE	Start	End													
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0	0	0	0	0	0	0	0	0	0	0		0
2	Power Purchase Agreements & Other Confidential Agreements				7,387,528	7,392,119	7,387,234	7,395,118	7,397,373	7,423,168	7,370,708	7,371,907	7,370,740	7,368,195	7,371,946		81,236,036
				Total	7,387,528	7,392,119	7,387,234	7,395,118	7,397,373	7,423,168	7,370,708	7,371,907	7,370,740	7,368,195	7,371,946		81,236,036

	Capacity Costs (MW)				January	February	March	April	May	June	July	August	September	October	November	December	YTD
B.	CONTRACT/COUNTERPARTY	TYPE	Start	End													
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0	0	0	0	0	0	0	0	0	0	0		0
2	Power Purchase Agreements & Other Confidential Agreements				Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies		

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 150001-EI

MONTHLY FUEL FILING

December 2015

GULF POWER

A SOUTHERN COMPANY

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
DECEMBER 2015

		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)	7,113,559	18,969,065	(11,855,506)	(62.50)	323,282,000	604,215,000	(280,933,000)	(46.50)	2.2004	3.1395	(0.94)	(29.91)
2	Hedging Settlement Costs (A2)	6,234,099	2,774,905	3,459,194	124.66	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	-	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
5	TOTAL COST OF GENERATED POWER	13,347,658	21,743,970	(8,396,312)	(38.61)	323,282,000	604,215,000	(280,933,000)	(46.50)	4.1288	3.5987	0.53	14.73
6	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
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	11,245,799	14,956,000	(3,710,201)	(24.81)	732,466,182	582,082,000	150,384,182	25.84	1.5353	2.5694	(1.03)	(40.25)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	490,567	0	490,567	100.00	23,567,000	0	23,567,000	100.00	2.0816	0.0000	2.08	0.00
12	TOTAL COST OF PURCHASED POWER	11,736,366	14,956,000	(3,219,634)	(21.53)	756,033,182	582,082,000	173,951,182	29.88	1.5524	2.5694	(1.02)	(39.58)
13	Total Available MWH (Line 5 + Line 12)	25,084,024	36,699,970	(11,615,946)	(31.65)	1,079,315,182	1,186,297,000	(106,981,818)	(9.02)				
14	Fuel Cost of Economy Sales (A6)	(155,147)	(273,000)	117,853	(43.17)	(10,481,176)	(12,740,000)	2,258,824	(17.73)	(1.4802)	(2.1429)	0.66	30.93
15	Gain on Economy Sales (A6)	(32,497)	(32,000)	(497)	1.55	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(1,332,622)	(5,120,000)	3,787,378	(73.97)	(239,706,816)	(238,236,000)	(1,470,816)	0.62	(0.5559)	(2.1491)	1.59	74.13
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(1,520,266)	(5,425,000)	3,904,734	(71.98)	(250,187,992)	(250,976,000)	788,008	(0.31)	(0.6076)	(2.1616)	1.55	71.89
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	23,563,758	31,274,970	(7,711,212)	(24.66)	829,127,190	935,321,000	(106,193,810)	(11.35)	2.8420	3.3438	(0.50)	(15.01)
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	58,742	58,918	(2,176)	(3.69)	1,996,562	1,762,000	234,562	13.31	2.8420	3.3438	(0.50)	(15.01)
22	T & D Losses *	1,183,754	1,471,305	(287,551)	(19.54)	41,652,138	44,001,000	(2,348,862)	(5.34)	2.8420	3.3438	(0.50)	(15.01)
23	TERRITORIAL KWH SALES	23,563,758	31,274,970	(7,711,212)	(24.66)	785,478,490	889,558,000	(104,079,510)	(11.70)	2.9999	3.5158	(0.52)	(14.67)
24	Wholesale KWH Sales	701,870	961,893	(260,023)	(27.03)	23,396,033	27,359,000	(3,962,967)	(14.49)	3.0000	3.5158	(0.52)	(14.67)
25	Jurisdictional KWH Sales	22,861,888	30,313,077	(7,451,189)	(24.58)	762,082,457	862,199,000	(100,116,543)	(11.61)	2.9999	3.5158	(0.52)	(14.67)
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	22,896,181	30,358,547	(7,462,366)	(24.58)	762,082,457	862,199,000	(100,116,543)	(11.61)	3.0044	3.5211	(0.52)	(14.67)
28	TRUE-UP	3,996,375	3,996,375	0	0.00	762,082,457	862,199,000	(100,116,543)	(11.61)	0.5244	0.4635	0.06	13.14
29	TOTAL JURISDICTIONAL FUEL COST	26,892,556	34,354,922	(7,462,366)	(21.72)	762,082,457	862,199,000	(100,116,543)	(11.61)	3.5288	3.9846	(0.46)	(11.44)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									3.5313	3.9875	(0.46)	(11.44)
32	GPIF Reward / (Penalty)	210,328	210,328	0	0.00	762,082,457	862,199,000	(100,116,543)	(11.61)	0.0276	0.0244	0.00	13.11
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.5589	4.0119	(0.45)	(11.29)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									3.559	4.012		

* Included for Informational Purposes Only

**(Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

SCHEDULE A1a

GULF POWER COMPANY
RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A-1
FOR THE MONTH OF: DECEMBER 2015

LINE	DESCRIPTION	REFERENCE	AMOUNT
1	Fuel Cost of System Net Generation	Schedule A-3, Line 7	$ 7,113,559
2	Fuel Related Transactions		0
3	Adjustments to Fuel Cost	Schedule A-2, Line A-7	0
4	Hedging Settlement Costs	Schedule A-2, Line A-5	6,234,099
5	Fuel Cost of Purchased Power	Schedule A-7	0
6	Energy Cost of Economy Purchases	Sch. A-9, Col. 4, Line 12	11,245,799
7	Demand & Non Fuel Cost of Purchased Power	Schedule A-9	0
8	Energy Payments to Qualified Facilities	Sch. A-8, Col. 8, Line 7	490,567
9	Fuel Cost of Power Sold	Sch. A-6, Col. 7, Total Line	(1,520,266)
10	Total Fuel and Net Power Transactions		$ 23,563,758

SCHEDULE A-1

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
DECEMBER 2015
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)	269,670,468	287,828,569	(18,158,101)	(6.31)	7,835,770,000	8,027,402,000	(191,632,000)	(2.39)	3.4415	3.5856	(0.14)	(4.02)
2	Hedging Settlement Costs (A2)	50,572,362	20,691,815	29,880,547	144.41	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
4	Adjustments to Fuel Cost (A2, Page 1) **	(102,102)	0	(102,102)	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
5	TOTAL COST OF GENERATED POWER	320,140,728	308,520,384	11,620,344	3.77	7,835,770,000	8,027,402,000	(191,632,000)	(2.39)	4.0856	3.8433	0.24	6.30
6	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
7	Energy Cost of Schedule C & X Econ. Purch.(Broker) (A9)	0.00	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
8	Energy Cost of Other Econ. Purch. (Nonbroker) (A9)	155,211,034	174,080,000	(18,868,966)	(10.84)	8,213,278,418	5,936,350,000	2,276,928,418	38.36	1.8898	2.9324	(1.04)	(35.55)
9	Energy Cost of Schedule E Economy Purch. (A9)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
11	Energy Payments to Qualifying Facilities (A8)	5,839,301	0	5,839,301	100.00	210,532,000	0	210,532,000	100.00	2.7736	0.0000	2.77	0.00
12	TOTAL COST OF PURCHASED POWER	161,050,335	174,080,000	(13,029,665)	(7.48)	8,423,810,418	5,936,350,000	2,487,460,418	41.90	1.9118	2.9324	(1.02)	(34.80)
13	Total Available MWH (Line 5 + Line 12)	481,191,063	482,600,384	(1,409,321)	(0.29)	16,259,580,418	13,963,752,000	2,295,828,418	16.44				
14	Fuel Cost of Economy Sales (A6)	(2,850,824)	(3,117,000)	266,176	(8.54)	(127,518,728)	(111,721,000)	(15,797,728)	14.14	(2.2356)	(2.7900)	0.55	19.87
15	Gain on Economy Sales (A6)	(674,392)	(488,801)	(185,591)	37.97	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Other Power Sales (A6)	(50,457,329)	(50,983,000)	525,671	(1.03)	(4,151,687,436)	(1,841,404,000)	(2,310,283,436)	125.46	(1.2153)	(2.7687)	1.55	56.11
17	TOTAL FUEL COSTS & GAINS OF POWER SALES (LINES 14 + 15 + 16)	(53,982,546)	(54,588,801)	606,256	(1.11)	(4,279,206,164)	(1,953,125,000)	(2,326,081,164)	119.10	(1.2615)	(2.7949)	1.53	54.86
18	Net Inadvertant Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
19	TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5 + 12 + 17)	427,208,518	428,011,583	(803,066)	(0.19)	11,980,374,254	12,010,627,000	(30,252,746)	(0.25)	3.5659	3.5636	0.00	0.06
20	Net Unbilled Sales *	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.00	0.00
21	Company Use *	841,532	745,694	95,838	12.85	23,599,422	20,925,300	2,674,122	12.78	3.5659	3.5636	0.00	0.06
22	T & D Losses *	19,839,097	22,851,752	(3,012,655)	(13.18)	556,355,946	641,254,700	(84,898,754)	(13.24)	3.5659	3.5636	0.00	0.06
23	TERRITORIAL KWH SALES	427,208,517	428,011,583	(803,066)	(0.19)	11,400,416,886	11,348,447,000	51,971,886	0.46	3.7473	3.7715	(0.02)	(0.64)
24	Wholesale KWH Sales	11,778,240	12,781,229	(1,002,989)	(7.85)	314,546,965	337,465,000	(22,918,035)	(6.79)	3.7445	3.7874	(0.04)	(1.13)
25	Jurisdictional KWH Sales	415,430,277	415,230,354	199,923	0.05	11,085,871,921	11,010,982,000	74,889,921	0.68	3.7474	3.7711	(0.02)	(0.63)
26	Jurisdictional Loss Multiplier	1.0015	1.0015							1.0015	1.0015		
27	Jurisdictional KWH Sales Adj. for Line Losses	416,053,422	415,853,200	200,222	0.05	11,085,871,921	11,010,982,000	74,889,921	0.68	3.7530	3.7767	(0.02)	(0.63)
28	TRUE-UP	47,956,495	47,956,495	0	0.00	11,085,871,921	11,010,982,000	74,889,921	0.68	0.4326	0.4355	(0.00)	(0.67)
29	TOTAL JURISDICTIONAL FUEL COST	464,009,917	463,809,695	200,222	0.04	11,085,871,921	11,010,982,000	74,889,921	0.68	4.1856	4.2122	(0.03)	(0.63)
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									4.1886	4.2152	(0.03)	(0.63)
32	GPIF Reward / (Penalty)	2,523,938	2,523,938	0	0.00	11,085,871,921	11,010,982,000	74,889,921	0.68	0.0228	0.0229	(0.00)	(0.44)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									4.2114	4.2381	(0.03)	(0.63)
34	FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									4.211	4.238		

* 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 2015

		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	6,957,837.35	18,765,033	(11,807,195.65)	(62.92)	267,222,277.82	284,893,215	(17,670,937.18)	(6.20)
1a	Other Generation	155,721.30	204,032	(48,310.70)	(23.68)	2,448,189.80	2,935,354	(487,164.20)	(16.60)
2	Fuel Cost of Power Sold	(1,520,266.01)	(5,425,000)	3,904,733.99	71.98	(53,982,545.71)	(54,588,801)	606,255.29	1.11
3	Fuel Cost - Purchased Power	11,245,799.38	14,956,000	(3,710,200.62)	(24.81)	155,211,034.53	174,080,000	(18,868,965.47)	(10.84)
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	490,567.24	0	490,567.24	100.00	5,839,300.75	0	5,839,300.75	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	6,234,099.00	2,774,905	3,459,194.00	124.66	50,572,362.43	20,691,815	29,880,547.43	144.41
6	Total Fuel & Net Power Transactions	23,563,758.26	31,274,970	(7,711,211.74)	(24.66)	427,310,619.62	428,011,583	(700,963.38)	(0.16)
7	AdjustmentsTo Fuel Cost*	0.00	0	0.00	0.00	(102,101.62)	0	(102,101.62)	100.00
8	Adj. Total Fuel & Net Power Transactions	23,563,758.26	31,274,970	(7,711,211.74)	(24.66)	427,208,518.00	428,011,583	(803,065.00)	(0.19)
B.	*KWH Sales*								
1	Jurisdictional Sales	762,082,457	862,199,000	(100,116,543)	(11.61)	11,085,871,921	11,010,982,000	74,889,921	0.68
2	Non-Jurisdictional Sales	23,396,033	27,359,000	(3,962,967)	(14.49)	314,546,965	337,465,000	(22,918,035)	(6.79)
3	Total Territorial Sales	785,478,490	889,558,000	(104,079,510)	(11.70)	11,400,418,886	11,348,447,000	51,971,886	0.46
4	Juris. Sales as % of Total Terr. Sales	97.0214	96.9244	0.0970	0.10	97.2409	97.0263	0.2146	0.22

**(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 2015

		CURRENT MONTH				PERIOD - TO - DATE			
				$ DIFFERENCE				$ DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT ($)	%	ACTUAL	ESTIMATED	AMOUNT ($)	%
C.	*True-up Calculation*								
1	Jurisdictional Fuel Revenue	29,752,013.31	37,351,158	(7,599,144.90)	(20.35)	476,514,008.57	477,004,648	(490,639.75)	(0.10)
2	Fuel Adj. Revs. Not Applicable to Period:								
2a	True-Up Provision	(3,996,375.00)	(3,996,375)	0.00	0.00	(47,956,495.00)	(47,956,495)	0.00	0.00
2b	Incentive Provision	(210,177.00)	(210,177)	0.00	0.00	(2,522,122.00)	(2,522,122)	0.00	0.00
3	Juris. Fuel Revenue Applicable to Period	25,545,461.31	33,144,606	(7,599,144.69)	(22.93)	426,035,391.57	426,526,031	(490,639.43)	(0.12)
4	Adjusted Total Fuel & Net Power Transactions (Line A8)	23,563,758.26	31,274,970	(7,711,211.74)	(24.66)	427,208,518.25	428,011,583	(803,064.75)	(0.19)
5	Juris. Sales % of Total KWH Sales (Line B4)	97.0214	96.9244	0.0970	0.10	97.2409	97.0263	0.2146	0.22
6	Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4*C5*1.0015)	22,896,180.99	30,358,547	(7,462,366.01)	(24.58)	416,053,422.19	415,853,200	200,222.19	0.05
7	True-Up Provision for the Month Over/(Under) Collection (C3-C6)	2,649,280.32	2,786,059	(136,778.68)	4.91	9,981,969.38	50,636,571	(40,654,601.62)	80.29
8	Interest Provision for the Month	3,370.84	1,662	1,708.84	(102.82)	(13,830.63)	(24,021)	10,190.37	42.42
9	Beginning True-Up & Interest Provision	11,396,994.91	3,864,714	7,532,280.91	(194.90)	(39,871,741.42)	(47,956,495)	8,084,753.58	16.86
10	True-Up Collected / (Refunded)	3,996,375.00	3,996,375	0.00	0.00	47,956,495.00	7,992,755	39,963,740.00	500.00
11	End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	18,046,021.07	10,648,810	7,397,211.07	(69.47)	18,052,892.33	10,648,810	7,404,082.33	(69.53)
12	Adjustment	0.00	0	0.00	0.00	(6,871.26)	0	(6,871.26)	100.00
13	End of Period - Total Net True-Up	18,046,021.07	10,648,810	7,397,211.07	(69.47)	18,046,021.07	10,648,810	7,397,211.07	(69.47)

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2015

		CURRENT MONTH			
		$		*DIFFERENCE*	
		ACTUAL	ESTIMATED	AMOUNT ($)	%
D.	*Interest Provision*				
1	BeginningTrue-Up Amount (C9)	11,396,994.91	3,864,714	7,532,280.91	194.90
	Ending True-Up Amount				
2	Before Interest (C7+C9+C10)	18,042,650.23	10,647,148	7,395,502.23	69.46
3	Total of Beginning & Ending True-Up Amts.	29,439,645.14	14,511,862	14,927,783.14	102.87
4	Average True-Up Amount	14,719,822.57	7,255,931	7,463,891.57	102.87
	Interest Rate				
5	1st Day of Reporting Business Month	0.15	0.15	0.0000	
	Interest Rate				
6	1st Day of Subsequent Business Month	0.40	0.40	0.0000	
7	Total (D5+D6)	0.55	0.55	0.0000	
8	Annual Average Interest Rate	0.28	0.28	0.0000	
9	Monthly Average Interest Rate (D8/12)	0.0229	0.0229	0.0000	
10	Interest Provision (D4*D9)	3,370.84	1,662	1,708.84	102.82
	Jurisdictional Loss Multiplier (From Schedule A-1)	1.0015	1.0015		

SCHEDULE A-3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2015

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	EST.	AMOUNT	%	ACTUAL	EST.	AMOUNT	%
	FUEL COST-NET GEN.($)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	LIGHTER OIL (B.L.)	25,745	62,342	(36,597)	(58.70)	1,463,041	998,464	464,577	46.53
2	COAL	662,894	8,732,714	(8,069,820)	(92.41)	163,343,301	156,240,099	7,103,202	4.55
3	GAS	6,061,951	9,817,746	(3,755,795)	(38.26)	101,319,573	126,967,619	(25,648,047)	(20.20)
4	GAS (B.L.)	283,861	292,024	(8,163)	(2.80)	2,520,828	2,841,024	(320,196)	(11.27)
5	LANDFILL GAS	69,944	64,239	5,705	8.88	755,723	781,363	(25,640)	(3.28)
6	OIL - C.T.	9,163	0	9,163	100.00	267,999	0	267,999	100.00
7	TOTAL ($)	7,113,559	18,969,065	(11,855,506)	(62.50)	269,670,468	287,828,569	(18,158,102)	(6.31)
	SYSTEM NET GEN. (MWH)								
8	LIGHTER OIL	0	0	0	0.00	0	0	0	0.00
9	COAL	10,071	244,083	(234,012)	(95.87)	4,082,288	4,113,246	(30,958)	(0.75)
10	GAS	310,925	358,032	(47,107)	(13.16)	3,728,131	3,888,422	(160,291)	(4.12)
11	LANDFILL GAS	2,256	2,100	156	7.43	24,554	25,734	(1,180)	(4.59)
12	OIL - C.T.	30	0	30	100.00	797	0	797	100.00
13	TOTAL (MWH)	323,282	604,215	(280,933)	(46.50)	7,835,770	8,027,402	(191,632)	(2.39)
	UNITS OF FUEL BURNED								
14	LIGHTER OIL (BBL)	358	692	(334)	(48.27)	16,256	9,342	6,914	74.01
15	COAL (TONS)	10,271	117,760	(107,489)	(91.28)	1,977,362	1,968,898	8,464	0.43
16	GAS (MCF) (1)	2,168,967	2,461,653	(292,686)	(11.89)	24,983,091	26,542,096	(1,559,005)	(5.87)
17	OIL - C.T. (BBL)	87	0	87	100.00	2,455	0	2,455	100.00
	BTU'S BURNED (MMBTU)								
18	COAL + GAS B.L. + OIL B.L.	198,654	2,598,985	(2,400,331)	(92.36)	44,969,512	43,786,033	1,183,479	2.70
19	GAS - Generation (1)	2,216,684	2,490,886	(274,202)	(11.01)	25,452,308	26,729,142	(1,276,834)	(4.78)
20	OIL - C.T.	509	0	509	100.00	14,304	0	14,304	100.00
21	TOTAL (MMBTU)	2,415,847	5,089,871	(2,674,024)	(52.54)	70,436,124	70,515,175	(79,051)	(0.11)
	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	3.11	40.39	(37.28)	(92.30)	52.10	51.24	0.86	1.68
24	GAS	96.18	59.26	36.92	62.30	47.58	48.44	(0.86)	(1.78)
25	LANDFILL GAS	0.70	0.35	0.35	100.00	0.31	0.32	(0.01)	(3.13)
26	OIL - C.T.	0.01	0.00	0.01	100.00	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)	71.86	90.09	(18.23)	(20.24)	90.00	106.88	(16.88)	(15.79)
29	COAL ($/TON)	64.54	74.16	(9.62)	(12.97)	82.61	79.35	3.26	4.11
30	GAS ($/MCF) (1)	2.85	4.02	(1.17)	(29.10)	4.06	4.78	(0.72)	(15.06)
31	OIL - C.T. ($/BBL)	105.32	0.00	105.32	100.00	109.16	0.00	109.16	100.00
	FUEL COST ($) / MMBTU								
32	COAL + GAS B.L. + OIL B.L.	4.90	3.50	1.40	40.00	3.72	3.66	0.06	1.64
33	GAS - Generation (1)	2.66	3.86	(1.20)	(31.09)	3.88	4.64	(0.76)	(16.38)
34	OIL - C.T.	18.02	0.00	18.02	100.00	18.74	0.00	18.74	100.00
35	TOTAL ($/MMBTU)	2.85	3.67	(0.82)	(22.34)	3.78	4.03	(0.25)	(6.20)
	BTU BURNED / KWH								
36	COAL + GAS B.L. + OIL B.L.	19,725	10,648	9,077	85.25	11,016	10,645	371	3.49
37	GAS - Generation (1)	7,230	7,070	160	2.26	6,952	7,021	(69)	(0.98)
38	OIL - C.T.	16,953	0	16,953	100.00	17,948	0	17,948	100.00
39	TOTAL (BTU/KWH)	7,629	8,534	(905)	(10.60)	9,096	8,903	193	2.17
	FUEL COST (¢ / KWH)								
40	COAL + GAS B.L. + OIL B.L.	9.66	3.72	5.94	159.68	4.10	3.89	0.21	5.40
41	GAS	1.95	2.74	(0.79)	(28.83)	2.72	3.27	(0.55)	(16.82)
42	LANDFILL GAS	3.10	3.06	0.04	1.31	3.08	3.04	0.04	1.32
43	OIL - C.T.	30.54	0.00	30.54	100.00	33.63	0.00	33.63	100.00
44	TOTAL (¢/KWH)	2.20	3.14	(0.94)	(29.94)	3.44	3.59	(0.15)	(4.18)

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 2015

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2015	(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 ($)	(m) Fuel Cost/ KWH (c/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	(980)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
2				0					Gas-G	0	1,021	0	0	0.00	0.00
3									Gas-S	0	1,021	0	0		0.00
4									Oil-S	0	138,131	0	0		0.00
5	Crist 5		75	(980)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
6				0					Gas-G	0	1,021	0	0	0.00	0.00
7									Gas-S	0	1,021	0	0		0.00
8									Oil-S	0	138,131	0	0		0.00
9	Crist 6		299	(1,359)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
10				0					Gas-G	0	1,021	0	0	0.00	0.00
11									Gas-S	0	1,021	0	0		0.00
12									Oil-S	0	138,131	0	0		0.00
13	Crist 7		475	(1,941)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
14				0					Gas-G	0	1,021	0	0	0.00	0.00
15									Gas-S	0	1,021	0	283,861		0.00
16									Oil-S	0	138,131	0	0		0.00
17	Scholz 1		0	0	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
18									Oil-S	0	0	0	0		0.00
19	Scholz 2		0	0	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	0	0	0		0.00
21	Smith 1		162	(805)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
22									Oil-S	0	138,222	0	0		0.00
23	Smith 2		195	(528)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
24									Oil-S	0	138,222	0	0		0.00
25	Smith 3		584	306,584	70.6	98.0	86.9	7,230	Gas-G	2,168,967	1,022	2,216,684	5,906,230	1.93	2.72
26	Smith A	(2)	40	30	0.1	100.0	66.2	16,967	Oil	87	138,539	509	9,163	30.54	105.32
27	Other Generation			4,341									155,721	3.59	0.00
28	Perdido			2,256					Landfill Gas				69,944	3.10	0.00
29	Daniel 1	(1)	255	(689)	0.0	10.0	0.0	0	Coal	0	0	0	0	0.00	0.00
30									Oil-S	0	138,847	0	0		0.00
31	Daniel 2	(1)	255	17,353	9.1	99.5	51.1	11,327	Coal	10,271	9,569	196,565	666,916	3.84	64.93
32									Oil-S	358	138,847	2,089	25,745		71.91
33	Total		2,415	323,282	18.0	90.0	27.5	7,629				2,415,847	7,117,580	2.20	

Notes & Adjust.: (1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

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)	
	Recoverable Fuel	7,113,559	2.20

SCHEDULE A-5

SYSTEM GENERATED FUEL COST - INVENTORY ANALYSIS
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2015

		CURRENT MONTH				PERIOD-TO-DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	LIGHT OIL								
1	*PURCHASES :*								
2	UNITS (BBL)	624	692	(68)	(9.83)	14,269	9,342	4,927	52.74
3	UNIT COST ($/BBL)	54.65	84.42	(29.77)	(35.26)	76.38	103.85	(27.47)	(26.45)
4	AMOUNT ($)	34,102	58,419	(24,317)	(41.63)	1,089,857	970,191	119,666	12.33
5	*BURNED :*								
6	UNITS (BBL)	363	692	(329)	(47.54)	16,896	9,342	7,554	80.86
7	UNIT COST ($/BBL)	71.81	90.09	(18.28)	(20.29)	90.04	106.88	(16.84)	(15.76)
8	AMOUNT ($)	26,067	62,342	(36,275)	(58.19)	1,521,242	998,464	522,778	52.36
9	*ENDING INVENTORY :*								
10	UNITS (BBL)	4,371	4,998	(627)	(12.55)	4,371	4,998	(627)	(12.55)
11	UNIT COST ($/BBL)	88.22	94.94	(6.72)	(7.08)	88.22	94.94	(6.72)	(7.08)
12	AMOUNT ($)	385,600	474,531	(88,931)	(18.74)	385,600	474,531	(88,931)	(18.74)
13	DAYS SUPPLY	N/A	N/A						
	COAL								
14	*PURCHASES :*								
15	UNITS (TONS)	43,846	94,750	(50,904)	(53.72)	2,119,944	2,026,777	93,167	4.60
16	UNIT COST ($/TON)	68.48	71.22	(2.74)	(3.85)	79.94	77.37	2.57	3.32
17	AMOUNT ($)	3,002,410	6,748,535	(3,746,125)	(55.51)	169,463,722	156,811,418	12,652,304	8.07
18	*BURNED :*								
19	UNITS (TONS)	10,271	117,760	(107,489)	(91.28)	1,977,362	1,968,898	8,464	0.43
20	UNIT COST ($/TON)	64.93	74.16	(9.23)	(12.45)	82.59	79.35	3.24	4.08
21	AMOUNT ($)	666,916	8,732,714	(8,065,798)	(92.36)	163,312,141	156,240,099	7,072,042	4.53
22	*ENDING INVENTORY :*								
23	UNITS (TONS)	699,045	570,419	128,626	22.55	699,045	570,419	128,626	22.55
24	UNIT COST ($/TON)	73.78	78.52	(4.74)	(6.04)	73.78	78.52	(4.74)	(6.04)
25	AMOUNT ($)	51,576,957	44,787,017	6,789,940	15.16	51,576,957	44,787,017	6,789,940	15.16
26	DAYS SUPPLY	40	32	8	25.00				
	GAS	(Reported on a MMBTU and $ basis)							
27	*PURCHASES :*								
28	UNITS (MMBTU)	2,258,405	2,510,886	(252,481)	(10.06)	26,451,831	26,899,142	(447,311)	(1.66)
29	UNIT COST ($/MMBTU)	2.62	3.95	(1.33)	(33.67)	3.74	4.72	(0.98)	(20.76)
30	AMOUNT ($)	5,914,882	9,905,738	(3,990,856)	(40.29)	98,835,759	126,873,289	(28,037,530)	(22.10)
31	*BURNED :*								
32	UNITS (MMBTU)	2,216,684	2,510,886	(294,202)	(11.72)	26,824,738	26,899,142	(74,404)	(0.28)
33	UNIT COST ($/MMBTU)	2.79	3.95	(1.16)	(29.37)	3.78	4.72	(0.94)	(19.92)
34	AMOUNT ($)	6,189,380	9,905,738	(3,716,358)	(37.52)	101,383,681	126,873,289	(25,489,608)	(20.09)
35	*ENDING INVENTORY :*								
36	UNITS (MMBTU)	668,435	0	668,435	100.00	668,435	0	668,435	100.00
37	UNIT COST ($/MMBTU)	2.66	0.00	2.66	100.00	2.66	0.00	2.66	100.00
38	AMOUNT ($)	1,780,793	0	1,780,793	100.00	1,780,793	0	1,780,793	100.00
	OTHER - C.T. OIL								
39	*PURCHASES :*								
40	UNITS (BBL) *	0	0	0	0.00	2,132	0	2,132	100.00
41	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	73.55	0.00	74.00	100.00
42	AMOUNT ($)	0	0	0	0.00	156,819	0	156,819	100.00
43	*BURNED :*								
44	UNITS (BBL)	87	0	87	100.00	2,455	0	2,455	100.00
45	UNIT COST ($/BBL)	105.32	0.00	105.32	100.00	109.16	0.00	109.16	100.00
46	AMOUNT ($)	9,163	0	9,163	100.00	267,999	0	267,999	100.00
47	*ENDING INVENTORY :*								
48	UNITS (BBL)	6,733	7,677	(944)	(12.30)	6,733	7,677	(944)	(12.30)
49	UNIT COST ($/BBL)	104.83	104.61	0.22	0.21	104.83	104.61	0.22	0.21
50	AMOUNT ($)	705,847	803,101	(97,254)	(12.11)	705,847	803,101	(97,254)	(12.11)
51	DAYS SUPPLY	3	4	(1)	(25.00)				

SCHEDULE A-6
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POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2015

	CURRENT MONTH								
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
	SOLD TO	TYPE AND SCHEDULE	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	(a) ¢ / KWH FUEL COST	(b) ¢ / KWH TOTAL COST	(5) x (6)(a) TOTAL $ FOR FUEL ADJ.	(5) x (6)(b) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		238,236,000	0	238,236,000	2.15	2.49	5,120,000	5,930,000
2	Various	Economy Sales	12,740,000	0	12,740,000	2.14	2.51	273,000	320,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	32,000	40,000
4	TOTAL ESTIMATED SALES		250,976,000	0	250,976,000	2.16	2.51	5,425,000	6,290,000
	ACTUAL								
5	Southern Company Interchange		84,615,294	0	84,615,294	1.74	1.92	1,472,152	1,621,838
6	A.E.C.	External	363,169	0	363,169	1.60	2.35	5,811	8,533
7	AECI	External	67,516	0	67,516	1.78	3.54	1,200	2,387
8	BAM	External	0	0	0	0.00	0.00	0	0
9	CARGILE	External	156,648	0	156,648	1.73	2.96	2,708	4,638
10	DUKE PWR	External	12,601	0	12,601	1.19	0.50	150	63
11	EAGLE EN	External	69,107	0	69,107	1.61	2.40	1,111	1,660
12	ENDURE	External	0	0	0	0.00	0.00	0	0
13	EU	External	0	0	0	0.00	0.00	0	0
14	EXELON	External	103,198	0	103,198	1.30	2.00	1,342	2,063
15	FPC	External	7,296	0	7,296	1.32	2.20	96	161
16	FPL	External	0	0	0	0.00	0.00	(102)	0
17	JPMVEC	External	0	0	0	0.00	0.00	0	0
18	MISO	External	1,761,980	0	1,761,980	1.35	1.98	23,718	34,925
19	MORGAN	External	140,067	0	140,067	1.30	1.73	1,823	2,425
20	NCEMC	External	148,815	0	148,815	1.53	2.38	2,278	3,535
21	NCMPA1	External	0	0	0	0.00	0.00	0	0
22	NOBLEAGP	External	0	0	0	0.00	0.00	0	0
23	OPC	External	66,323	0	66,323	1.43	2.48	948	1,645
24	ORLANDO	External	24,538	0	24,538	1.22	2.48	299	609
25	PJM	External	4,430,986	0	4,430,986	1.43	2.43	63,147	107,715
26	SCE&G	External	1,028,655	0	1,028,655	1.76	2.23	18,148	22,917
27	SEC	External	237,100	0	237,100	1.56	2.54	3,699	6,026
28	SEPA	External	70,832	0	70,832	1.94	3.54	1,376	2,508
29	TAL	External	0	0	0	0.00	0.00	0	0
30	TEA	External	1,237,632	0	1,237,632	1.52	2.24	18,848	27,742
31	TECO	External	0	0	0	0.00	0.00	(130)	0
32	TENASKA	External	6,898	0	6,898	1.38	2.90	95	200
33	TVA	External	192,670	0	192,670	1.81	3.05	3,492	5,869
34	WRI	External	355,145	0	355,145	1.43	2.16	5,088	7,688
35	Less: Flow-Thru Energy		(9,558,633)	0	(9,558,633)	1.46	1.46	(139,530)	(139,530)
36	SEPA		2,245,760	2,245,760	0	0.00	0.00	0	0
37	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	32,497	32,497
38	Other transactions including adj.		162,404,395	164,500,330	(2,095,935)	0.00	0.00	0	0
39	TOTAL ACTUAL SALES		250,187,992	166,746,090	83,441,902	0.61	0.69	1,520,266	1,725,616
40	Difference in Amount		(788,008)	166,746,090	(167,534,098)	(1.55)	(1.82)	(3,904,734)	(4,564,384)
41	Difference in Percent		(0.31)	0.00	(66.75)	(71.76)	(72.51)	(71.98)	(72.57)

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 37

SCHEDULE A-6
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POWER SOLD
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2015

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) c / KWH FUEL COST	(6) (b) c / KWH TOTAL COST	(7) TOTAL $ FOR FUEL ADJ.	(8) TOTAL COST $
	ESTIMATED								
1	Southern Company Interchange		1,841,404,000	0	1,841,404,000	2.77	3.06	50,983,000	56,398,000
2	Various	Economy Sales	111,721,000	0	111,721,000	2.79	3.06	3,117,000	3,419,000
3		Gain on Econ. Sales	0	0	0	0.00	0.00	488,801	502,000
4	TOTAL ESTIMATED SALES		1,953,125,000	0	1,953,125,000	2.79	3.09	54,588,801	60,319,000
	ACTUAL								
5	Southern Company Interchange		1,929,836,148	0	1,929,836,148	2.75	2.99	53,011,210	57,752,936
6	A.E.C.	External	28,278,778	0	28,278,778	2.36	2.91	668,024	821,547
7	AECI	External	468,955	0	468,955	2.29	3.07	10,728	14,381
8	BAM	External	5,903	0	5,903	2.00	3.27	118	193
9	CARGILE	External	2,106,009	0	2,106,009	2.59	3.23	54,456	68,068
10	DUKE PWR	External	2,429,803	0	2,429,803	2.41	4.42	58,464	107,291
11	EAGLE EN	External	2,764,974	0	2,764,974	2.54	3.64	70,144	100,777
12	ENDURE	External	115,729	0	115,729	2.70	4.50	3,129	5,203
13	EU	External	12,535	0	12,535	1.56	2.43	195	305
14	EXELON	External	3,733,510	0	3,733,510	2.36	3.07	88,035	114,438
15	FPC	External	676,285	0	676,285	2.34	4.49	15,800	30,372
16	FPL	External	2,793,104	0	2,793,104	2.66	4.24	74,191	118,461
17	JPMVEC	External	932,603	0	932,603	2.49	3.21	23,235	29,978
18	MISO	External	5,746,627	0	5,746,627	1.76	2.56	101,197	147,206
19	MORGAN	External	3,917,993	0	3,917,993	2.35	2.86	92,068	112,099
20	NCEMC	External	1,969,142	0	1,969,142	2.16	2.99	42,599	58,974
21	NCMPA1	External	6,300	0	6,300	45.53	2.64	2,868	166
22	NOBLEAGP	External	26,528	0	26,528	1.59	2.80	422	743
23	OPC	External	1,127,271	0	1,127,271	2.40	3.63	27,107	40,939
24	ORLANDO	External	647,042	0	647,042	3.12	4.84	20,160	31,321
25	PJM	External	14,469,776	0	14,469,776	2.03	3.29	293,395	476,655
26	SCE&G	External	12,441,206	0	12,441,206	2.42	3.05	301,079	379,083
27	SEC	External	565,521	0	565,521	2.02	2.90	11,442	16,424
28	SEPA	External	16,074,218	0	16,074,218	1.97	2.83	315,907	455,033
29	TAL	External	256,337	0	256,337	2.28	3.94	5,839	10,096
30	TEA	External	16,961,131	0	16,961,131	2.15	3.17	365,485	537,632
31	TECO	External	1,941,429	0	1,941,429	2.51	3.72	48,796	72,211
32	TENASKA	External	70,568	0	70,568	2.86	4.25	2,016	2,999
33	TVA	External	4,361,492	0	4,361,492	2.39	3.87	104,197	168,591
34	WRI	External	2,617,959	0	2,617,959	1.90	2.62	49,728	68,519
35	Less: Flow-Thru Energy		(116,708,678)	0	(116,708,678)	2.19	2.19	(2,553,881)	(2,553,881)
36	SEPA		15,535,432	15,535,432	0	0.00	0.00	0	0
37	Economy Energy Sales Gain (1)		0	0	0	0.00	0.00	674,392	674,392
38	Other transactions including adj.		2,323,024,534	1,879,365,213	443,659,321	0.00	0.00	0	0
39	TOTAL ACTUAL SALES		4,279,206,164	1,894,900,645	2,384,305,519	1.26	1.38	53,982,546	59,188,759
40	Difference in Amount		2,326,081,164	1,894,900,645	431,180,519	(1.53)	(1.71)	(606,255)	(1,130,241)
41	Difference in Percent		119.10	0.00	22.08	(54.84)	(55.34)	(1.11)	(1.87)

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 37

SCHEDULE A-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
FOR THE MONTH OF: DECEMBER 2015

(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 2015

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.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	4,840,000	0	0	0	3.52	3.52	170,290
3	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	2,257
4	Ascend Performance Materials	COG 1	18,592,000	0	0	0	1.70	1.70	316,035
5	International Paper	COG 1	135,000	0	0	0	1.47	1.47	1,986
6	TOTAL		23,567,000	0	0	0	2.08	2.08	490,567

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.
	ESTIMATED								
1			0	0	0	0	0.00	0.00	0
	ACTUAL								
2	Bay County/Engen, LLC	Contract	54,177,000	0	0	0	3.53	3.53	1,912,024
3	Renewable Energy Customers	COG 1	0	0	0	0	0.00	0.00	2,320
4	Ascend Performance Materials	COG 1	155,374,000	0	0	0	2.51	2.51	3,899,093
5	International Paper	COG 1	981,000	0	0	0	2.64	2.64	25,864
6	TOTAL		210,532,000	0	0	0	2.77	2.77	5,839,301

SCHEDULE A-9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2015

	(1) PURCHASED FROM	CURRENT MONTH (2) TOTAL KWH PURCHASED	(3) TRANS. COST ¢ / KWH	(4) TOTAL $ FOR FUEL ADJ.	PERIOD - TO - DATE (5) TOTAL KWH PURCHASED	(6) TRANS. COST ¢ / KWH	(7) TOTAL $ FOR FUEL ADJ.
	ESTIMATED						
1	Southern Company Interchange	72,147,000	2.23	1,610,000	1,411,171,000	2.90	40,952,000
2	Economy Energy	3,497,000	2.80	98,000	50,614,000	3.18	1,607,000
3	Other Purchases	506,438,000	2.62	13,248,000	4,474,565,000	2.94	131,521,000
4	TOTAL ESTIMATED PURCHASES	582,082,000	2.57	14,956,000	5,936,350,000	2.93	174,080,000
	ACTUAL						
5	Southern Company Interchange	196,076,963	1.54	3,026,562	1,774,085,600	2.36	41,785,334
6	Non-Associated Companies	32,729,666	0.05	17,368	654,779,690	0.82	5,394,224
7	Alabama Electric Co-op	0	0.00	0	0	0.00	0
8	Purchased Power Agreement Energy	374,703,000	2.23	8,339,937	4,059,459,000	2.73	110,699,715
9	Other Wheeled Energy	32,000	0.00	N/A	618,135,000	0.00	N/A
10	Other Transactions	138,483,186	0.02	21,239	1,223,527,806	0.01	158,573
11	Less: Flow-Thru Energy	(9,558,633)	1.67	(159,307)	(116,708,678)	2.42	(2,826,812)
12	TOTAL ACTUAL PURCHASES	732,466,182	1.54	11,245,799.19	8,213,278,418	1.89	155,211,034
13	Difference in Amount	150,384,182	(1.03)	(3,710,201)	2,276,928,418	(1.04)	(18,868,966)
14	Difference in Percent	25.84	(40.08)	(24.81)	38.36	(35.49)	(10.84)

2015 CAPACITY CONTRACTS
GULF POWER COMPANY

	Capacity Costs ($)	CONTRACT TYPE	TERM Start	TERM End	January	February	March	April	May	June	July	August	September	October	November	December	YTD
A.	CONTRACT/COUNTERPARTY																
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0	0	0	0	0	0	0	0	0	0	0	(8,431)	(8,431)
2	Power Purchase Agreements & Other Confidential Agreements				7,387,528	7,392,119	7,387,234	7,395,118	7,397,373	7,423,168	7,370,708	7,371,907	7,370,740	7,368,195	7,371,946	7,369,532	88,605,568
				Total	7,387,528	7,392,119	7,387,234	7,395,118	7,397,373	7,423,168	7,370,708	7,371,907	7,370,740	7,368,195	7,371,946	7,361,101	88,597,137

	Capacity Costs (MW)	TYPE	Start	End	January	February	March	April	May	June	July	August	September	October	November	December
B.	CONTRACT/COUNTERPARTY															
1	Southern Intercompany Interchange	SES Opco	2/18/2007	5 Yr Notice	0	0	0	0	0	0	0	0	0	0	0	(52)
2	Power Purchase Agreements & Other Confidential Agreements				Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies	Varies

Schedule E-1A

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
TO BE INCLUDED IN THE PERIOD JANUARY 2017 - DECEMBER 2017

1.	Estimated over/(under)-recovery for the period January 2016 - December 2016 (Sch. E-1B, Page 2, line C9)	$	27,383,731
2.	Final over/(under)-recovery for the period January 2015 - December 2015 (Exhibit CSB-1, Schedule 1, line 3)		(1,324,066)
3.	Total over/(under)-recovery (Lines 1 + 2) To be included in January 2017 - December 2017		26,059,665
4.	Jurisdictional kWh sales for the period January 2017 - December 2017		11,022,525,000
5.	True-Up Factor (Line 3/Line 4) x 100(¢/kWH)		(0.2364)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 45
PARTY: GULF POWER COMPANY – (DIRECT)
DESCRIPTION: C. S. Boyett CSB-2

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2016 - JUNE 2016 / ESTIMATED FOR JULY 2016 - DECEMBER 2016

				JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	TOTAL SIX MONTHS
				(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation		21,899,067	15,153,243	6,888,569	15,179,780	15,949,057	30,181,393	$105,251,108.43
	1a	Fuel Cost of Hedging Settlement		5,195,191.00	6,107,019.00	6,681,995 00	5,239,140.00	5,718,593.00	4,737,258 00	$33,679,196.00
	2	Fuel Cost of Power Sold		(8,649,415.54)	(4,530,225.28)	(5,754,573.44)	(3,381,847.31)	(2,416,103.49)	(7,245,919 54)	($31,978,085.20)
	3	Fuel Cost of Purchased Power		14,620,878.25	11,022,035.97	14,450,553.38	10,180,007.70	14,011,811.53	16,141,784 21	$80,427,071.04
	3a	Demand & Non-Fuel Cost of Purchased Power		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	3b	Energy Payments to Qualified Facili ies		574,810.71	377,155.48	345,590.67	456,594.55	517,022.76	632,540.33	$2,903,714.50
	4	Energy Cost of Economy Purchases		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation		197,027	143,006	173,299	175,595	182,292	192,072	$1,063,291.49
	6	Adjustments to Fuel Cost		0 00	4.77	11.37	2.78	7.56	19.95	$46.43
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)		33,837,558.87	28,272,239.45	22,785,444.68	27,849,272.68	33,962,680.05	44,639,147.56	$191,346,343.29
B	1	Jurisdic ional KWH Sales		891,087,234	756,584,301	765,402,935	752,614,350	953,141,310	1,105,160,254	5,223,990,384
	2	Non-Jurisdictional KWH Sales		27,628,571	23,343,210	21,801,748	21,366,561	25,996,698	30,120,479	150,257,267
	3	TOTAL SALES (Lines B1 + B2)		918,715,805	779,927,511	787,204,683	773,980,911	979,138,008	1,135,280,733	5,374,247,651
	4	Jurisdictional % of Total Sales (Line B1/B3)		96 9927%	97.0070%	97.2305%	97.2394%	97.3449%	97.3469%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	(1)	31,733,646	26,696,738	27,092,412	26,701,932	33,711,744	41,860,632	$187,797,104.47
	2	True-Up Provision		1,614,173	1,614,174	1,614,174	1,614,174	1,614,174	1,614,174	$9,685,043.00
	2a	Incentive Provision		(220,533)	(220,534)	(220,534)	(220,534)	(220,534)	(220,534)	($1,323,203.00)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)		33,127,286.14	28,090,378.31	28,486,052 25	28,095,571.64	35,105,383.78	43,254,272 35	$196,158,944.47
	4	Fuel & Net Power Transactions (Line A7)		33,837,559	28,272,239	22,785,445	27,849,273	33,962,680	44,639,148	$191,346,343.29
	5	Jurisdic ional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0015)		32,869,192	27,467,190	22,187,633	27,121,086	33,110,528	43,520,009	$186,275,638.98
	6	Over/(Under) Recovery (Line C3-C5)		258,094.23	623,187.91	6,298,418.86	974,485.28	1,994,855.44	(265,736.23)	$9,883,305.49
	7	Interest Provision		5,783.54	5,540.48	6,449.19	6,501.73	5,805.64	5,894.66	$35,975.24
	8	Adjustments (2)		0 00	0.00	(75,803.69)	0.00	0.00	0.00	($75,803.69)
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2016 - JUNE 2016**								$9,843,477.04

* (Gain)/Loss on sales of natural gas

Notes 1: Projected Revenues based on the current approved 2016 Fuel Factor excluding revenue taxes of: 3.6474 ¢/kWh
2: Audit finding adjustment
3: January - June Scherer adjustment

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2016 - JUNE 2016 / ESTIMATED FOR JULY 2016 - DECEMBER 2016

				JULY PROJECTION	AUGUST PROJECTION	SEPTEMBER PROJECTION	OCTOBER PROJECTION	NOVEMBER PROJECTION	DECEMBER PROJECTION	TOTAL PERIOD
				(a)	(a)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation		26,930,726.00	26,849,391.00	18,355,096 00	7,425,546.00	10,953,889.00	14,987,697 00	$210,753,453.43
	1a	Fuel Cost of Hedging Settlement		3,983,180.00	4,055,860.00	3,983,814 00	3,719,065.00	3,017,580.00	2,287,103 00	$54,725,798.00
	2	Fuel Cost of Power Sold		(6,522,000.00)	(7,059,000.00)	(3,174,000 00)	(616,000.00)	(497,000.00)	(2,915,000 00)	($52,761,085.20)
	3	Fuel Cost of Purchased Power		16,165,000.00	15,910,000.00	16,947,000.00	20,415,000.00	13,419,000.00	14,046,000 00	$177,329,071.04
	3a	Demand & Non-Fuel Cost Of Purchased Power		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	3b	Energy Payments to Qualified Facilities		346,000.00	346,000.00	346,000.00	402,000.00	355,000.00	355,000.00	$5,053,714.50
	4	Energy Cost of Economy Purchases		0.00	0.00	0.00	0.00	0.00	0 00	$0.00
	5	O her Generation		264,703.00	264,703.00	256,180.00	176,634.00	170,952.00	176,634.00	$2,373,097.49
	6	Adjustments to Fuel Cost *		0 00	0.00	0.00	0.00	0.00	0.00	$46.43
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)		41,167,609.00	40,366,954.00	36,714,090 00	31,522,245.00	27,419,421.00	28,937,434.00	397,474,095.69
B	1	Jurisdic ional KWH Sales		1,179,840,000	1,166,950,000	1,021,925,000	839,139,000	734,554,000	826,023,000	10,992,421,384
	2	Non-Jurisdictional KWH Sales		33,527,000	33,627,000	29,508,000	25,237,000	23,805,000	28,101,000	324,062,267
	3	TOTAL SALES (Lines B1 + B2)		1,213,367,000	1,200,577,000	1,051,433,000	864,376,000	758,359,000	854,124,000	11,316,483,651
	4	Jurisdictional % Of Total Sales (Line B1/B3)		97 2369%	97.1991%	97.1935%	97.0803%	96.8610%	96.7100%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	**(1)**	43,033,176.11	42,563,029.62	37,273,425.63	30,606,536.79	26,791,930.81	30,128,147 23	$398,193,350.67
	2	True-Up Provision		1,614,174.00	1,614,174.00	1,614,174 00	1,614,174.00	1,614,174.00	1,614,174 00	$19,370,087.00
	2a	Incentive Provision		(220,534.00)	(220,534.00)	(220,534 00)	(220,534.00)	(220,534.00)	(220,534 00)	($2,646,407.00)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)		$44,426,816.11	$43,956,669.62	$38,667,065.63	$32,000,176.79	$28,185,570.81	$31,521,787 23	$414,917,030.67
	4	Fuel & Net Power Transactions (Line A7)		41,167,609.00	40,366,954.00	36,714,090.00	31,522,245.00	27,419,421.00	28,937,434 00	$397,474,095.69
	5	Jurisdic ional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0015)		40,090,151 96	39,295,170.46	35,737,234.63	30,647,792.85	26,598,563.46	28,027,370.51	$386,671,922.85
	6	Over/(Under) Recovery (Line C3-C5)		4,336,664.15	4,661,499.16	2,929,831.00	1,352,383.94	1,587,007.35	3,494,416.72	$28,245,107.81
	7	Interest Provision		6,202 33	7,118.81	7,812.60	7,982.11	7,938.84	7,960.37	$80,990.30
	8	Adjustments (3)		0 00	0.00	0.00	0 00	0.00	(866,563.19)	($942,366.88)
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2016 - DECEMBER 2016**								$27,383,731.23

* (Gain)/Loss on sales of natural gas

Notes 1: Projected Revenues based on the current approved 2016 Fuel Factor excluding revenue taxes of: 3.6474 ¢/kWh
2: Audit finding adjustment
3: January - June Scherer adjustment

SCHEDULE E-1B-1

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2016 - JUNE 2016 / ESTIMATED FOR JULY 2016 - DECEMBER 2016

	DOLLARS				kWh				¢/kWh			
	ESTIMATED/ ACTUAL	EST MATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	EST MATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMT.	%
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1 Fuel Cost of System Net Generation [1]	210,753,453	286,397,897	(75,644,444)	(26.41)	6,782,674,000	8,146,827,000	(1,364,153,000)	(16.74)	3.1072	3.5155	(0.4083)	(11.61)
1a Fuel Cost of Hedging Settlement	54,725,798	0	54,725,798	100.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
2 Other Generation	2,373,097	2,857,236	(484,139)	(16.94)	76,850,000	81,612,000	(4,762,000)	(5 83)	3.0880	3.5010	(0.4130)	(11.80)
3 Adjustments to Fuel Cost ***	46	0	46	100.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
4 TOTAL COST OF GENERATED POWER	267,852,395	289,255,133	(21,402,738)	(7.40)	6,859,524,000	8,228,439,000	(1,368,915,000)	(16.64)	3.9048	3.5153	0.3895	11.08
5 Energy Cost of Other Economy Purchases (Nonbroker)	177,329,071	223,394,000	(46,064,929)	(20.62)	8,807,866,927	6,944,290,000	1,863,576,927	26 84	2.0133	3.2169	(1.2036)	(37.41)
6 Energy Payments to Qualifying Facilities	5,053,715	5,291,000	(237,286)	(4.48)	190,183,000	192,036,000	(1,853,000)	(0 96)	2.6573	2.7552	(0.0979)	(3.55)
7 TOTAL COST OF PURCHASED POWER	182,382,786	228,685,000	(46,302,214)	(20.25)	8,998,049,927	7,136,326,000	1,861,723,927	26.09	2.0269	3.2045	(1.1776)	(36.75)
8 Total Available kWh (Line 4 + Line 7)	450,235,181	517,940,133	(67,704,952)	(13.07)	15,857,573,927	15,364,765,000	492,808,927	3 21	2.8392	3.3710	(0.5318)	(15.78)
9 Fuel Cost of Economy Sales	(2,357,542)	(2,673,000)	315,458	(11.80)	(113,727,971)	(113,630,000)	(97,971)	0.09	2.0730	2.3524	(0.2794)	(11.88)
10 Gain on Economy Sales	(489,951)	(564,000)	74,049	(13.13)	0	0						
11 Fuel Cost of Other Power Sales	(49,913,592)	(83,652,000)	33,738,408	(40.33)	(3,818,442,456)	(3,256,519,000)	(561,923,456)	17.26	1.3072	2.5688	(1.2616)	(49.11)
12 TOTAL FUEL COST AND GAINS ON POWER SALES	(52,761,085)	(86,889,000)	34,127,915	(39.28)	(3,932,170,427)	(3,370,149,000)	(562,021,427)	16.68	1.3418	2.5782	(1.2364)	(47.96)
13 (LINES 9+10+11)												
14 **TOTAL FUEL & NET POWER TRANSACTIONS**	397,474,096	431,051,133	(33,577,037)	(7.79)	11,925,403,500	11,994,616,000	(69,212,500)	(0 58)	3.3330	3.5937	(0.2607)	(7.25)
(LINES 8+12)												
15 Company Use *	602,943	743,501	(140,558)	(18.90)	18,090,106	20,689,000	(2,598,894)	(12 56)	3.3330	3.5937	(0.2607)	(7.25)
16 T & D Losses *	19,692,355	21,900,870	(2,208,515)	(10.08)	590,829,743	609,424,000	(18,594,257)	(3.05)	3.3330	3.5937	(0.2607)	(7.25)
17 TERRITORIAL (SYSTEM) SALES	397,474,096	431,051,133	(33,577,037)	(7.79)	11,316,483,651	11,364,503,000	(48,019,349)	(0.42)	3.5123	3.7930	(0.2807)	(7.40)
18 Wholesale Sales	11,382,189	12,536,358	(1,154,169)	(9.21)	324,062,267	330,513,000	(6,450,733)	(1 95)	3.5123	3.7930	(0.2807)	(7.40)
19 Jurisdictional Sales	386,091,907	418,514,775	(32,422,868)	(7.75)	10,992,421,384	11,033,990,000	(41,568,616)	(0 38)	3.5123	3.7930	(0.2807)	(7.40)
20 Jurisdictional Loss Multiplier	1.0015	1.0015										
21 Jurisdictional Sales Adj. for Line Losses (Line 19 x 1.0015)	386,671,923	419,142,547	(32,470,624)	(7.75)	10,992,421,384	11,033,990,000	(41,568,616)	(0 38)	3.5176	3.7986	(0.2810)	(7.40)
22 TRUE-UP **	(19,370,087)	(19,370,087)	0	0.00	10,992,421,384	11,033,990,000	(41,568,616)	(0 38)	(0.1762)	(0.1755)	(0.0007)	0.40
23 TOTAL JURISDICTIONAL FUEL COST	367,301,836	399,772,460	(32,470,624)	(8.12)	10,992,421,384	11,033,990,000	(41,568,616)	(0.38)	3 3414	3.6231	(0.2817)	(7.78)
24 Revenue Tax Factor									1.00072	1.00072		
25 Fuel Factor Adjusted for Revenue Taxes									3.3438	3.6257	(0.2819)	(7.78)
26 GP F Reward / (Penalty) **	2,648,312	2,648,312	0	0.00	10,992,421,384	11,033,990,000	(41,568,616)	(0 38)	0.0241	0.0240	0.0001	(0.42)
27 Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.3679	3.6497	(0.2818)	(7.72)
28 **FUEL FACTOR ROUNDED TO NEAREST .001(¢/kWh)**									3.368	3.650	(0.2820)	(7.73)

[1] Includes portion of Gulf's 25% ownership of Scherer Unit 3 available to the native load customers

* Included for informational purposes only.

** ¢/kWh calculation based on jurisdictional kWh sales.

*** (Gain)/Loss on sales of natural gas

Note: Amounts included in the Estimated/Actual column represent 6 months actual and 6 months estimate.

SCHEDULE E-2

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2016 - JUNE 2016 / ESTIMATED FOR JULY 2016 - DECEMBER 2016

LINE	LINE DESCRIPTION	(a) JANUARY ACTUAL	(b) FEBRUARY ACTUAL	(c) MARCH ACTUAL	(d) APRIL ACTUAL	(e) MAY ACTUAL	(f) JUNE ACTUAL	(g) JULY ESTIMATED	(h) AUGUST ESTIMATED	(i) SEPTEMBER ESTIMATED	(j) OCTOBER ESTIMATED	(k) NOVEMBER ESTIMATED	(l) DECEMBER EST MATED	(m) TOTAL
	$													
1	Fuel Cost of System Generation [1]	21,899,067	15,153,243	6,888,569	15,179,780	15,949,057	30,181,393	26,930,726	26,849,391	18,355,096	7,425,546	10,953,889	14,987,697	210,753,453
1a	Other Generation	197,027	143,006	173,299	175,595	182,292	192,072	264,703	264,703	256,180	176,634	170,952	176,634	2,373,097
2	Fuel Cost of Power Sold	(8,649,416)	(4,530,225)	(5,754,573)	(3,381,847)	(2,416,103)	(7,245,920)	(6,522,000)	(7,059,000)	(3,174,000)	(616,000)	(497,000)	(2,915,000)	(52,761,085)
3	Fuel Cost of Purchased Power	14,620,878	11,022,036	14,450,553	10,180,008	14,011,812	16,141,784	16,165,000	15,910,000	16,947,000	20,415,000	13,419,000	14,046,000	177,329,071
3a	Demand & Non-Fuel Cost of Pur Power	0	0	0	0	0	0	0	0	0	0	0	0	0
3b	Qualifying Facilities	574,811	377,155	345,591	456,595	517,023	632,540	346,000	346,000	346,000	402,000	355,000	355,000	5,053,715
4	Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Hedging Settlement	5,195,191	6,107,019	6,681,995	5,239,140	5,718,593	4,737,258	3,983,180	4,055,860	3,983,814	3,719,065	3,017,580	2,287,103	54,725,798
6	Adjustment to Fuel Cost	0	5	11	3	8	20	0	0	0	0	0	0	46
7	**Total Fuel & Net Power Trans.** (Sum of Lines 1 - 6)	$ 33,837,559	$ 28,272,239	$ 22,785,445	$ 27,849,273	$ 33,962,680	$ 44,639,148	$ 41,167,609	$ 40,366,954	$ 36,714,090	$ 31,522,245	$ 27,419,421	$ 28,937,434	$ 397,474,096
8	System kWh Sold	918,715,805	779,927,511	787,204,683	773,980,911	979,138,008	1,135,280,733	1,213,367,000	1,200,577,000	1,051,433,000	864,376,000	758,359,000	854,124,000	11,316,483,651
8a	Jurisdictional % of Total Sales	96 9927%	97.0070%	97.2305%	97.2394%	97.3449%	97.3469%	97.2369%	97.1991%	97.1935%	97.0803%	96 8610%	96.7100%	
9	Cost per kWh Sold (¢/kWh)	3.6831	3.6250	2 8945	3 5982	3.4686	3 9320	3.3928	3 3623	3.4918	3.6468	3.6156	3.3880	3 5123
9a	Jurisdictional Loss Multiplier	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015
9b	Jurisdictional Cost (¢/kWh)	3.6886	3.6304	2 8988	3.6036	3.4738	3 9379	3.3979	3 3673	3.4970	3.6523	3.6210	3.3931	3.5176
10	GPIF (¢/kWh) *	0.0247	0.0291	0.0288	0.0293	0.0231	0.0200	0.0187	0.0189	0.0216	0.0263	0.0300	0.0267	0.0241
11	True-Up (¢/kWh) *	(0.1811)	(0.2134)	(0 2109)	(0 2145)	(0.1694)	(0.1461)	(0.1368)	(0.1383)	(0.1580)	(0.1924)	(0.2197)	(0.1954)	(0.1762)
12	TOTAL	3.5322	3.4461	2.7167	3.4184	3 3275	3 8118	3.2798	3 2479	3.3606	3.4862	3.4313	3.2244	3 3655
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	3.5347	3.4486	2.7187	3.4209	3 3299	3 8145	3.2822	3 2502	3.3630	3.4887	3.4338	3.2267	3.3679
15	**Recovery Factor Rounded to the Nearest .001 ¢/kWh**	3.535	3.449	2.719	3.421	3.330	3 815	3 282	3 250	3 363	3.489	3.434	3.227	3 368

* ¢/kWh calculations based on jurisdictional kWh sales

[1] Includes portion of Gulf's 25% ownership of Scherer Unit 3 available to the native load customers

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2016 - JUNE 2016 / ESTIMATED FOR JULY 2016 - DECEMBER 2016

		JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	JULY EST MATED	AUGUST EST MATED	SEPTEMBER EST MATED	OCTOBER EST MATED	NOVEMBER EST MATED	DECEMBER EST MATED	TOTAL
	FUEL COST - NET GEN. ($)													
1	LIGHTER O L (B.L.)	273,641	90,896	14,403	116,308	113,248	89,741	49,002	62,321	50,511	63,509	37,224	61,381	1,022,184
2	COAL	14,419,596	8,927,832	72,731	7,733,556	9,748,853	20,962,788	14,229,243	14,209,801	10,038,042	2,250,272	691,358	2,753,856	106,037,928
2a	Coal at Scherer	0	0	0	0	0	0	2,436,668	2,430,825	2,201,066	2,104,805	2,042,554	2,082,332	13,298,250
3	GAS - Generation	7,029,050	5,920,192	6,591,204	7,150,073	6,038,575	9,162,640	10,099,272	10,005,909	5,941,283	2,775,868	7,996,933	9,863,545	88,574,543
4	GAS (B L.)	342,490	307,812	306,001	263,856	144,949	85,609	315,451	339,445	316,743	341,933	293,141	337,424	3,394,854
5	Landfill Gas	31,317	64,024	66,675	66,581	69,481	64,933	65,793	65,793	63,631	65,793	63,631	65,793	753,445
6	O L - C.T.	0	(14,507)	10,855	25,002	16,243	7,754	0	0	0	0	0	0	45,347
7	TOTAL ($)	22,096,094	15,296,249	7,061,868	15,355,375	16,131,349	30,373,465	27,195,429	27,114,094	18,611,276	7,602,180	11,124,841	15,164,331	213,126,551
	SYSTEM NET GEN. (MWH)													
8	LIGHTER O L (B.L.)	0	0	0	0	0	0	0	0	0	0	0	0	0
9	COAL	341,940	215,442	(5,811)	165,427	213,409	491,409	419,219	428,950	306,910	67,033	20,155	83,468	2,747,551
9a	Coal at Scherer	0	0	0	0	0	0	87,106	86,256	77,550	73,313	72,141	73,495	469,861
10	GAS	334,154	309,411	396,608	360,000	247,140	353,107	374,382	371,510	166,725	5,720	320,668	378,450	3,617,875
11	Landfill Gas	1,031	1,997	2,218	2,129	2,191	2,019	2,100	2,100	2,031	2,100	2,031	2,100	24,047
12	O L - C.T.	(8)	51	31	60	29	27	0	0	0	0	0	0	190
13	TOTAL (MWH)	677,117	526,901	393,046	527,616	462,769	846,562	882,807	888,816	553,216	148,166	414,995	537,513	6,859,524
	UNITS OF FUEL BURNED													
14	LIGHTER O L (BBL)	4,616	1,487	128	1,524	1,791	1,426	799	987	799	987	586	944	16,074
15	COAL excl. Scherer (TON) (2)	182,589	114,070	186	89,269	114,846	260,331	193,640	202,099	144,521	34,001	11,880	42,854	1,390,286
16	GAS-all (MCF) (1)	2,308,658	2,159,823	2,775,193	2,491,711	1,832,226	2,512,138	2,579,442	2,567,632	1,117,607	0	2,191,901	2,578,347	25,114,678
17	O L - C.T. (BBL)	0	110	104	239	160	76	0.00	0.00	0.00	0.00	0.00	0.00	689
	BTU'S BURNED (MMBTU)													
18	COAL + GAS B.L. + O L B.L.	3,934,609	2,451,054	73,166	2,000,531	2,572,541	5,574,909	5,411,422	5,558,460	4,174,856	1,589,635	1,038,840	1,735,344	36,115,367
19	GAS-Generation (1)	2,343,327	2,202,476	2,834,019	2,526,762	1,837,499	2,518,204	2,631,031	2,618,985	1,139,959	0	2,235,740	2,629,914	25,517,916
20	O L - C.T.	0	639	602	1,387	931	444	0	0	0	0	0	0	4,003
21	TOTAL (MMBTU)	6,277,936	4,654,169	2,907,787	4,528,680	4,410,971	8,093,557	8,042,453	8,177,445	5,314,815	1,589,635	3,274,580	4,365,258	61,637,286

(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.

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2016 - JUNE 2016 / ESTIMATED FOR JULY 2016 - DECEMBER 2016

		JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	JULY EST MATED	AUGUST EST MATED	SEPTEMBER EST MATED	OCTOBER EST MATED	NOVEMBER EST MATED	DECEMBER EST MATED	TOTAL
	GENERATION MIX (% MWH)													
22	LIGHTER O L (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	50.50	40.89	(1.48)	31.36	46.12	58.05	57.35	57.96	69.49	94.72	22.24	29.20	46.91
24	GAS-Generation	49.35	58.72	100.91	68.23	53.40	41.71	42.41	41.80	30.14	3.86	77.27	70.41	52.74
25	Landfill Gas	0.15	0.38	0.56	0.40	0.47	0.24	0.24	0.24	0.37	1.42	0.49	0.39	0.35
26	O L - C.T.	0.00	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
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 O L ($/BBL)	59.29	61.13	112.90	76.33	63.22	62.93	61.31	63.13	63.20	64.34	63.55	64.99	63.59
29	COAL ($/TON) (2)	78.97	78.27	391.03	86.63	84.89	80.52	73.48	70.31	69.46	66.18	58.20	64.26	76.27
30	GAS + B L. ($/MCF) (1)	3.11	2.82	2.42	2.90	3.28	3.60	3.93	3.93	5.37	0.00	3.70	3.89	3.57
31	O L - C.T.	0.00	(131.88)	104.39	104.61	101.52	102.03	0.00	0.00	0.00	0.00	0.00	0.00	65.82
	FUEL COST $ / MMBTU													
32	COAL + GAS B.L. + O L B.L.	3.82	3.81	5.37	4.06	3.89	3.79	3.15	3.07	3.02	2.99	2.95	3.02	3.43
33	GAS-Generation (1)	2.92	2.62	2.26	2.76	3.19	3.56	3.74	3.72	4.99	0.00	3.50	3.68	3.38
34	O L - C.T.	0.00	(22.70)	18.03	18.03	17.45	17.46	0.00	0.00	0.00	0.00	0.00	0.00	11.33
35	TOTAL ($/MMBTU)	3.48	3.24	2.35	3.34	3.60	3.72	3.34	3.28	3.44	4.63	3.33	3.42	3.41
	BTU BURNED BTU / KWH													
36	COAL + GAS B.L. + O L B.L.	11,507	11,377	(12,591)	12,093	12,055	11,345	10,688	10,789	10,859	11,327	11,256	11,056	11,225
37	GAS-Generation (1)	7,149	7,224	7,249	7,135	7,617	7,257	7,192	7,216	7,195	0	7,095	7,056	7,206
38	O L - C.T.	0	12,529	19,419	23,117	32,103	16,444	0	0	0	0	0	0	21,068
39	TOTAL (BTU/KWH)	9,374	8,944	7,550	8,715	9,701	9,653	9,222	9,312	9,790	11,327	8,037	8,241	9,120
	FUEL COST CENTS / KWH													
40	COAL + GAS B.L. + O L B.L.	4.40	4.33	(6.77)	4.90	4.69	4.30	3.36	3.31	3.28	3.39	3.32	3.34	3.85
41	GAS-Generation	2.10	1.91	1.66	1.99	2.44	2.59	2.70	2.69	3.56	48.53	2.49	2.61	2.45
42	Landfill Gas	3.04	3.21	3.01	3.13	3.17	3.22	3.13	3.13	3.13	3.13	3.13	3.13	3.13
43	O L - C.T.	0.00	0.00	35.02	41.67	56.01	28.72	0.00	0.00	0.00	0.00	0.00	0.00	23.87
44	TOTAL (¢/KWH)	3.26	2.90	1.80	2.91	3.49	3.59	3.08	3.05	3.36	5.13	2.68	2.82	3.11

(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.

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2016

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	2,595	4.7	100.0	39.3	16,053	Coal	1,840	11,320	41,658	158,795	6.12	86.30
2	4			0					Gas - G	0	1,023	0	0	0.00	0.00
3									Gas - S	870	1,023	890	14,713		16.91
4									Oil - S	48	138,131	281	5,462		113.79
5	Crist 5		75	2,978	5.3	100.0	40.8	15,790	Coal	2,075	11,331	47,024	179,076	6.01	86.30
6	5			0					Gas - G	0	1,023	0	0	0.00	0.00
7									Gas - S	1,965	1,023	2,010	33,225		16.91
8									Oil - S	214	138,131	1,244	24,199		112.90
9	Crist 6		299	69,147	31.1	99.8	56.3	11,300	Coal	34,782	11,232	781,346	3,001,758	4.34	86.30
10	6			0					Gas - G	0	1,023	0	0	0.00	0.00
11									Gas - S	9,091	1,023	9,300	153,730		16.91
12									Oil - S	7	138,131	42	823		117.57
13	Crist 7		475	131,356	37.2	96.1	57.9	10,955	Coal	63,835	11,271	1,438,973	5,509,084	4.19	86.30
14	7			0					Gas - G	0	1,023	0	0	0.00	0.00
15									Gas - S	8,327	1,023	8,519	140,822		16.91
16									Oil - S	52	138,131	303	5,901		113.48
17	Smith 1		162	34,154	28.3	98.7	43.1	11,346	Coal	18,182	10,656	387,502	1,523,094	4.46	83.77
18									Oil - S	853	137,838	4,941	47,760		55.99
19	Smith 2		195	(723)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	N/A
20									Oil - S	0	137,838	0	0		N/A
21	Smith 3		584	327,789	75.4	99.9	94.2	7,149	Gas - G	2,288,405	1,024	2,343,327	6,832,023	2.08	2.99
22	Smith A (CT)	(2)	40	(8)	0.0	100.0	0.0	0	Oil	0	138,539	0	0	0.00	N/A
23	Other Generation			6,365					Gas				197,027	3.10	N/A
24	Perdido			1,031					Landfill Gas				31,317	3.04	N/A
25	Daniel 1	(1)	255	51,776	27.3	99.2	37.0	11,295	Coal	27,730	10,545	584,799	1,815,848	3.51	65.48
26									Oil - S	2,999	138,800	17,472	165,114	N/A	55.06
27	Daniel 2	(1)	255	50,657	26.7	99.8	38.8	11,957	Coal	34,145	8,870	605,725	2,235,963	4.41	65.48
28									Oil - S	443	138,800	2,580	24,382		55.04
29	Total		2,415	677,117	37.7	99.0	54.5	9,374				6,277,936	22,100,116	3.26	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

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)	
	Recoverable Fuel	22,096,094	3.26

Docket No. 160001-EI
2016 Est/Act True-Up Filing
Exhibit CSB-2, Page 8 of 33

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2016

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	2,900	5.6	99.7	48.6	14,482	Coal	1,834	11,450	41,999	161,253	5.56	87.92
2				0					Gas - G	0	1,021	0	0	0.00	0.00
3									Gas - S	1,068	1,021	1,090	29,701		27.81
4									Oil - S	110	138,131	636	12,386		112.60
5	Crist 5		75	3064	5.9	100.0	53.0	14,116	Coal	1,897	11,400	43,251	166,792	5.44	87.92
6				0					Gas - G	0	1,021	0	0	0.00	0.00
7									Gas - S	1,427	1,021	1,457	39,699		27.82
8									Oil - S	52	138,131	301	5,849		112.89
9	Crist 6		299	27,006	13.0	100.0	50.0	12,091	Coal	14,317	11,403	326,517	1,258,825	4.66	87.93
10				0					Gas - G	0	1,021	0	0	0.00	0.00
11									Gas - S	7,904	1,021	8,070	219,858		27.82
12									Oil - S	0	138,131	0	0		0.00
13	Crist 7		475	90,504	27.4	99.7	52.6	10,947	Coal	43,319	11,436	990,787	3,808,769	4.21	87.92
14				0					Gas - G	0	1,021	0	0	0.00	0.00
15									Gas - S	667	1,021	681	18,555		27.82
16									Oil - S	33	138,131	193	3,747		113.55
17	Smith 1		162	22,257	19.7	77.2	38.8	11,700	Coal	12,254	10,625	260,404	849,487	3.82	69.32
18									Oil - S	694	138,943	4,047	38,226		55.08
19	Smith 2		195	(496)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil - S	0	138,943	0	0		0.00
21	Smith 3		584	304,889	75.0	100.0	86.6	7,224	Gas - G	2,148,757	1,025	2,202,476	5,777,186	1.89	2.69
22	Smith A (CT)	(2)	40	51	0.2	100.0	78.1	12,529	Oil	110	138,539	639	11,514	22.58	104.67
23	Other Generation			4,522					Gas				143,006	3.16	0.00
24	Perdido			1,997					Landfill Gas				64,024	3.21	0.00
25	Daniel 1	(1)	255	26,791	15.1	100.0	29.8	11,475	Coal	15,300	10,047	307,431	1,016,245	3.79	66.42
26									Oil - S	411	138,267	2,387	21,076	N/A	51.28
27	Daniel 2	(1)	255	43,416	24.5	98.5	42.7	10,612	Coal	25,149	9,160	460,714	1,670,483	3.85	66.42
28									Oil - S	187	138,267	1,089	9,611		51.40
29	Total		2,415	526,901	31.3	98.2	52.2	8,944				4,654,169	15,326,292	2.91	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

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)	
	Inventory Adj Oil - Plant Daniel	0.11	
	Inventory Adj Oil - Plant Smith	(26,021)	
	Recoverable Fuel	15,296,250	2.90

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2016

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	(1,156)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
2	4			-					Gas - G	0	1,017	0	0	0.00	0.00
3									Gas - S	0	1,017	0	0		0.00
4									Oil - S	0	138,500	0	0		0.00
5	Crist 5		75	(758)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
6	5			0					Gas - G	0	1,017	0	0	0.00	0.00
7									Gas - S	6,030	1,017	6,133	142,046		23.56
8									Oil - S	26	138,500	151	2,935		112.88
9	Crist 6		299	(3,574)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
10	6			0					Gas - G	0	1,017	0	0	0.00	0.00
11									Gas - S	0	1,017	0	0		0.00
12									Oil - S	0	138,500	0	0		0.00
13	Crist 7		475	3,084	0.9	22.6	17.4	19,199	Coal	2,655	11,151	59,211	240,132	7.79	90.43
14	7			0					Gas - G	0	1,017	0	0	0.00	0.00
15									Gas - S	6,961	1,017	7,079	163,956		23.55
16									Oil - S	102	138,500	591	11,467		112.42
17	Smith 1		162	(754)	0.0	76.4	0.0	0	Coal	0	0	0	0	0.00	N/A
18									Oil - S	0	138,500	0	0		N/A
19	Smith 2		195	(524)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	N/A
20									Oil - S	0	138,500	0	0		N/A
21	Smith 3		558	390,932	94.3	100.0	99.1	7,249	Gas - G	2,762,202	1,026	2,834,020	6,417,904	1.64	2.32
22	Smith A (CT)	(2)	36	31	0.1	100.0	66.4	19,419	Oil	104	138,500	602	10,855	35.02	104.38
23	Other Generation			5,676					Gas				173,299	3.05	N/A
24	Perdido			2,218					Landfill Gas				66,675	3.01	N/A
25	Daniel 1	(1)	255	(1,413)	0.0	85.7	0.0	0	Coal	0	0	0	0	0.00	N/A
26									Oil - S	0	138,500	0	0		N/A
27	Daniel 2	(1)	255	(716)	0.0	85.7	0.0	0	Coal	0	0	0	0	0.00	N/A
28									Oil - S	0	138,500	0	0		N/A
29	Total		2,385	393,046	22.2	79.9	27.7	7,550				2,907,787	7,229,269	1.84	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

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)	
(2,470)	Coal Inventory Adjustment - Dani	(163,916)	
	Other Coal Adjustments - Daniel	536	
	Recoverable Fuel	7,061,868	1.80

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2016

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	(1,060)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
2	4			0					Gas - G	0	1,021	0	0	0.00	0.00
3									Gas - S	0	1,021	0	0		0.00
4									Oil - S	0	138,500	0	0		0.00
5	Crist 5		75	(1,061)	0.0	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
6	5			0					Gas - G	0	1,021	0	0	0.00	0.00
7									Gas - S	0	1,021	0	0		0.00
8									Oil - S	0	138,500	0	0		0.00
9	Crist 6		299	4,244	2.0	22.0	37.0	16,714	Coal	3,097	11,452	70,934	279,024	6.57	90.09
10	6			0					Gas - G	0	1,021	0	0	0.00	0.00
11									Gas - S	4,239	1,021	4,328	46,275		10.92
12									Oil - S	219	138,500	1,272	24,679		112.69
13	Crist 7		475	146,566	42.9	94.9	53.0	11,105	Coal	71,929	11,314	1,627,609	6,480,443	4.42	90.09
14	7			0					Gas - G	0	1,021	0	0	0.00	0.00
15									Gas - S	19,931	1,021	20,350	217,581		10.92
16									Oil - S	379	138,500	2,205	42,791		112.91
17	Smith 1		162	(477)	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	N/A
18									Oil - S	0	138,500	0	0		N/A
19	Smith 2		195	(434)	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	N/A
20									Oil - S	0	138,500	0	0		N/A
21	Smith 3		558	354,131	88.1	96.6	95.9	7,135	Gas - G	2,467,541	1,024	2,526,761	6,974,478	1.97	2.83
22	Smith A (CT)	(2)	36	60	0.2	89.4	67.7	23,117	Oil	239	138,500	1,387	25,002	41.67	104.61
23	Other Generation			5,869					Gas				175,595	2.99	N/A
24	Perdido			2,129					Landfill Gas				66,580	3.13	N/A
25	Daniel 1	(1)	255	8,886	4.8	99.3	27.6	16,081	Coal	7,367	9,698	142,900	505,949	5.69	68.68
26									Oil - S	628	138,500	3,655	33,131		52.76
27	Daniel 2	(1)	255	8,763	4.8	99.8	30.0	14,327	Coal	6,876	9,130	125,546	472,162	5.39	68.67
28									Oil - S	298	138,500	1,733	15,706		52.70
29	Total		2,385	527,616	30.7	73.2	44.8	8,715				4,528,680	15,359,396	2.91	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

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)	
	Recoverable Fuel	15,355,375	2.91

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2016 Est/Act True-Up Filing
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SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2016

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	556	1.0	88.2	20.8	0	Coal	0	0	0	0	0.00	0.00
2	4			0					Gas - G	11,383	1,019	11,599	48,688	0.00	4.28
3									Gas - S	1,763	1,019	1,797	7,542		4.28
4									Oil - S	0	138,500	0	0		0.00
5	Crist 5		75	(786)	0.0	88.2	0.0	0	Coal	0	0	0	0	0.00	0.00
6	5			0					Gas - G	0	1,019	0	0	0.00	0.00
7									Gas - S	0	1,019	0	0		0.00
8									Oil - S	0	138,500	0	0		0.00
9	Crist 6		299	40,019	18.0	83.7	47.4	9,249	Coal	16,003	11,565	370,149	1,422,492	3.55	88.89
10	6			0					Gas - G	122819	1,019	125153	525336.13	0.00	4.28
11									Gas - S	12,927	1,019	13,173	55,294		4.28
12									Oil - S	934	138,500	5,440	62,346		66.75
13	Crist 7		475	154,824	43.8	85.3	51.4	11,212	Coal	75,167	11,547	1,735,907	6,681,527	4.32	88.89
14	7			0					Gas - G	0	1,019	0	0	0.00	0.00
15									Gas - S	19,198	1,019	19,562	82,113		4.28
16									Oil - S	325	138,500	1,888	21,642		66.59
17	Smith 1		162	(404)	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	N/A
18									Oil - S	0	138,500	0	0		N/A
19	Smith 2		195	(464)	0.0	0.0	0.0	0	Coal	0	0	0	0	0.00	N/A
20									Oil - S	0	138,500	0	0		N/A
21	Smith 3		558	230,570	55.5	68.4	98.8	7,376	Gas - G	1,664,136	1,022	1,700,747	5,282,259	2.29	3.17
22	Smith A (CT)	(2)	36	29	0.1	99.3	75.5	32,103	Oil	160	138,500	931	16,243	56.01	101.52
23	Other Generation			5,902					Gas				182,292	3.09	N/A
24	Perdido			2,191					Landfill Gas				69,481	3.17	N/A
25	Daniel 1	(1)	255	2,371	1.2	100.0	18.3	18,071	Coal	2,250	9,522	42,847	156,696	6.61	69.64
26									Oil - S	153	138,500	888	8,398		54.89
27	Daniel 2	(1)	255	27,961	14.7	100.0	27.5	13,543	Coal	21,426	8,837	378,685	1,492,160	5.34	69.64
28									Oil - S	379	138,500	2,205	20,862		55.04
29	Total		2,385	462,769	26.1	71.9	46.0	9,701				4,410,971	16,135,371	3.49	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

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)	
	Recoverable Fuel	16,131,349	3.49

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2016

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	15,277	28.3	99.8	54.9	12,634	Coal	8,366	11,535	193,004	711,181	4.66	85.01
2	4			0					Gas - G	0	1,019	0	0	0.00	0.00
3									Gas - S	988	1,019	1007	20,396		20.64
4									Oil - S	118	138,500	688	7,887		66.84
5	Crist 5		75	13,975	25.9	100.0	52.1	13,487	Coal	8,157	11,553	188,476	693,414	4.96	85.01
6	5			0					Gas - G	0	1,019	0	0	0.00	0.00
7									Gas - S	1,289	1,019	1,314	26,611		20.64
8									Oil - S	98	138,500	568	6,505		66.38
9	Crist 6		299	124,529	57.8	99.9	57.8	11,068	Coal	59,920	11,501	1,378,280	5,093,706	4.09	85.01
10	6			0					Gas - G	0	1,019	0	0	0.00	0.00
11									Gas - S	1,761	1,019	1,794	36,335		20.63
12									Oil - S	523	138,500	3044	34,892		66.72
13	Crist 7		475	211,370	61.8	98.8	61.8	10,817	Coal	99,198	11,524	2,286,316	8,432,667	3.99	85.01
14	7			0					Gas - G	12,149	1,019	12,380	250,731	0.00	20.64
15									Gas - S	110	1,019	112	2,267		20.61
16									Oil - S	147	138,500	855	9,796		66.64
17	Smith 1		162	881	0.8	0.0	0.0	0	Coal	0	0	0	0	0.00	N/A
18									Oil - S	0	138,500	0	0		N/A
19	Smith 2		195	898	0.6	0.0	0.0	0	Coal	0	0	0	0	0.00	N/A
20									Oil - S	0	138,500	0	0		N/A
21	Smith 3		558	345,867	86.1	100.0	101.1	7,245	Gas - G	2,495,841	1,004	2,505,824	8,719,837	2.52	3.49
22	Smith A (CT)	(2)	36	27	0.1	100.0	73.4	16,444	Oil	76	138,500	444	7,754	28.72	102.03
23	Other Generation			6,100					Gas				192,072	3.15	N/A
24	Perdido			2,019					Landfill Gas				64,933	3.22	N/A
25	Daniel 1	(1)	255	54,199	29.5	100.0	43.1	12,135	Coal	36,449	9,023	657,729	2,597,729	4.79	71.27
26									Oil - S	405	138,500	2,351	22,980		56.74
27	Daniel 2	(1)	255	71,420	38.9	99.4	39.1	12,022	Coal	48,241	8,899	858,585	3,438,112	4.81	71.27
28									Oil - S	135	138,500	786	7,681		56.90
29	Total		2,385	846,562	49.3	84.7	56.5	9,653				8,093,557	30,377,486	3.59	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil

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)	
	Recoverable Fuel	30,373,464	3.59

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: JULY 2016

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	0	0.0	94.4	0.0	N/A	Coal	0	0	0	0	N/A	N/A
2	4								Gas - G	0	0	0	0		
3									Gas - S	0	0	0	0		
4									Oil - S	0	0	0	0		
5	Crist 5		75	0	0.0	94.4	0.0	N/A	Coal	0	0	0	0	N/A	N/A
6	5								Gas - G	0	0	0	0		
7									Gas - S	0	0	0	0		
8									Oil - S	0	0	0	0		
9	Crist 6		299	61,783	27.8	93.8	71.3	10,750	Coal	27,888	11,908	664,171	2,137,251	3.46	76.64
10	6								Gas - G	0	0	0	0		
11									Gas - S	0	0	0	0		
12									Oil - S	0	0	0	0		
13	Crist 7		475	243,370	68.9	94.4	73.2	10,494	Coal	107,239	11,908	2,553,929	8,218,350	3.38	76.64
14	7								Gas - G	0	0	0	0		
15									Gas - S	0	0	0	0		
16									Oil - S	0	0	0	0		
17	Smith 1		0	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
18									Oil - S	0	0	0	0		
19	Smith 2		0	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
20									Oil - S	0	0	0	0		
21	Smith 3		556	365,810	88.4	96.5	91.6	7,192	Gas - G	2,579,442	1,020	2,631,031	9,834,569	2.69	3.81
22	Smith A (CT)	(2)	32	0	0.0	98.4	0.0	N/A	Oil	0	0	0	0	N/A	N/A
23	Scherer 3	(3)	164	87,106	71.5	96.9	14.8	11,093	Coal	56,676	8,525	966,295	2,436,668	2.80	42.99
24	Other Generation			8,572					Gas				264,703	3.09	N/A
25	Perdido			2,100					Landfill Gas				65,793	3.13	N/A
26	Daniel 1	(1)	255	63,665	33.6	96.5	27.9	10,629	Coal	32,659	10,360	676,669	2,162,065	3.40	66.20
27									Oil - S	0	0	0	0		
28	Daniel 2	(1)	255	50,401	26.6	96.5	28.3	10,628	Coal	25,854	10,360	535,678	1,711,577	3.40	66.20
29									Oil - S	0	0	0	0		
30	Gas,BL								Gas	9,804	1,020	10,000	315,451	N/A	32.18
31	Ltr. Oil								Oil	799	139,400	4,680	49,002	N/A	61.33
32	Total		2,186	882,807	54.3	95.6	56.6	9,922				8,042,453	27,195,429	3.08	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil
(3) Represents the portion of Gulf's 25% ownership available to the native load customers

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: AUGUST 2016

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	4,122	7.4	94.4	56.7	11,461	Coal	1,990	11,872	47,244	146,272	3.55	73.50
2	4								Gas - G	0	0	0	0		
3									Gas - S	0	0	0	0		
4									Oil - S	0	0	0	0		
5	Crist 5		75	4,129	7.4	94.4	56.8	11,373	Coal	1,978	11,872	46,961	145,396	3.52	73.51
6	5								Gas - G	0	0	0	0		
7									Gas - S	0	0	0	0		
8									Oil - S	0	0	0	0		
9	Crist 6		299	60,090	27.0	93.8	67.0	10,797	Coal	27,325	11,872	648,800	2,008,758	3.34	73.51
10	6								Gas - G	0	0	0	0		
11									Gas - S	0	0	0	0		
12									Oil - S	0	0	0	0		
13	Crist 7		475	238,908	67.6	94.4	71.5	10,519	Coal	105,839	11,872	2,513,057	7,780,710	3.26	73.51
14	7								Gas - G	0	0	0	0		
15									Gas - S	0	0	0	0		
16									Oil - S	0	0	0	0		
17	Smith 1		0	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
18									Oil - S	0	0	0	0		
19	Smith 2		0	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
20									Oil - S	0	0	0	0		
21	Smith 3		556	362,938	87.7	96.5	91.8	7,216	Gas - G	2,567,632	1,020	2,618,985	9,741,206	2.68	3.79
22	Smith A (CT)	(2)	32	0	0.0	98.4	0.0	N/A	Oil	0	0	0	0	N/A	N/A
23	Scherer 3	(3)	164	86,256	70.8	96.9	14.6	11,161	Coal	56,520	8,516	962,696	2,430,825	2.82	43.01
24	Other Generation			8,572					Gas				264,703	3.09	N/A
25	Perdido			2,100					Landfill Gas				65,793	3.13	N/A
26	Daniel 1	(1)	255	61,270	32.3	96.5	25.0	10,791	Coal	32,693	10,112	661,190	2,077,621	3.39	63.55
27									Oil - S	0	0	0	0		
28	Daniel 2	(1)	255	60,431	31.9	96.5	25.1	10,801	Coal	32,274	10,112	652,732	2,051,044	3.39	63.55
29									Oil - S	0	0	0	0		
30	Gas,BL								Gas	19,608	1,020	20,000	339,445	N/A	17.31
31	Ltr. Oil								Oil	987	139,400	5,780	62,321	N/A	63.14
32	Total		2,186	888,816	54.7	95.6	58.9	9,985				8,177,445	27,114,094	3.05	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil
(3) Represents the portion of Gulf's 25% ownership available to the native load customers

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: SEPTEMBER 2016

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) (bs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	0	0.0	94.3	0	N/A	Coal	0	0	0	0	N/A	N/A
2	4								Gas - G	0	0	0	0		
3									Gas - S	0	0	0	0		
4									Oil - S	0	0	0	0		
5	Crist 5		75	0	0.0	94.3	0	N/A	Coal	0	0	0	0	N/A	N/A
6	5								Gas - G	0	0	0	0		
7									Gas - S	0	0	0	0		
8									Oil - S	0	0	0	0		
9	Crist 6		299	28,074	12.6	93.9	65.2	10,821	Coal	12,814	11,854	303,783	923,047	3.29	72.03
10	6								Gas - G	0	0	0	0		
11									Gas - S	0	0	0	0		
12									Oil - S	0	0	0	0		
13	Crist 7		475	215,227	60.9	94.4	66.6	10,602	Coal	96,252	11,854	2,281,859	6,933,442	3.22	72.03
14	7								Gas - G	0	0	0	0		
15									Gas - S	0	0	0	0		
16									Oil - S	0	0	0	0		
17	Smith 1		0	0	0.0	0	0	N/A	Coal	0	0	0	0	N/A	N/A
18									Oil - S	0	0	0	0		
19	Smith 2		0	0	0.0	0	0	N/A	Coal	0	0	0	0	N/A	N/A
20									Oil - S	0	0	0	0		
21	Smith 3		556	158,429	38.3	45.1	87.7	7,195	Gas - G	1,117,607	1,020	1,139,959	5,685,103	3.59	5.09
22	Smith A (CT)	(2)	32	0	0.0	98.3	0	N/A	Oil	0	0	0	0	N/A	N/A
23	Scherer 3	(3)	164	77,550	63.7	96.9	13.6	11,229	Coal	51,181	8,508	870,844	2,201,066	2.84	43.01
24	Other Generation			8,296					Gas				256,180	3.09	N/A
25	Perdido			2,031					Landfill Gas				63,631	3.13	N/A
26	Daniel 1	(1)	255	38,801	20.5	96.5	21.1	11,127	Coal	21,753	9,924	431,740	1,338,463	3.45	61.53
27									Oil - S	0	0	0	0		
28	Daniel 2	(1)	255	24,808	13.1	96.5	23.2	10,962	Coal	13,702	9,924	271,950	843,090	3.40	61.53
29									Oil - S	0	0	0	0		
30	Gas,BL								Gas	9,804	1,020	10,000	316,743	N/A	32.31
31	Ltr. Oil								Oil	799	139,400	4,680	50,511	N/A	63.22
32	Total		2,186	553,216	34.0	82.5	51.9	10,501				5,314,815	18,611,276	3.36	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil
(3) Represents the portion of Gulf's 25% ownership available to the native load customers

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: OCTOBER 2016

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	2,073	3.7	94.4	57.6	11,420	Coal	999	11,851	23,673	72,977	3.52	73.05
2	4								Gas - G	0	0	0	0		
3									Gas - S	0	0	0	0		
4									Oil - S	0	0	0	0		
5	Crist 5		75	2,078	3.7	94.4	57.7	11,331	Coal	993	11,851	23,545	72,581	3.49	73.09
6	5								Gas - G	0	0	0	0		
7									Gas - S	0	0	0	0		
8									Oil - S	0	0	0	0		
9	Crist 6		299	8,264	3.7	93.8	69.1	10,798	Coal	3,765	11,851	89,238	275,091	3.33	73.07
10	6								Gas - G	0	0	0	0		
11									Gas - S	0	0	0	0		
12									Oil - S	0	0	0	0		
13	Crist 7		475	23,256	6.6	64.0	60.4	10,732	Coal	10,530	11,851	249,589	769,398	3.31	73.07
14	7								Gas - G	0	0	0	0		
15									Gas - S	0	0	0	0		
16									Oil - S	0	0	0	0		
17	Smith 1		0	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
18									Oil - S	0	0	0	0		
19	Smith 2		0	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
20									Oil - S	0	0	0	0		
21	Smith 3		558	0	0.0	0.0	0.0	N/A	Gas - G	0	0	0	2,599,234	N/A	N/A
22	Smith A (CT)	(2)	36	0	0.0	98.4	0.0	N/A	Oil	0	0	0	0	N/A	N/A
23	Scherer 3	(3)	164	73,313	60.2	96.9	12.4	11,346	Coal	48,918	8,502	831,787	2,104,805	2.87	43.03
24	Other Generation			5,720					Gas				176,634	3.09	N/A
25	Perdido			2,100					Landfill Gas				65,793	3.13	N/A
26	Daniel 1	(1)	255	23,354	12.3	96.5	22.4	11,022	Coal	13,177	9,767	257,401	788,685	3.38	59.85
27									Oil - S	0	0	0	0		
28	Daniel 2	(1)	255	8,008	4.2	96.5	22.8	11,067	Coal	4,537	9,767	88,622	271,540	3.39	59.85
29									Oil - S	0	0	0	0		N/A
30	Gas,BL								Gas	19,608	1,020	20,000	341,933	N/A	17.44
31	Ltr. Oil								Oil	987	139,400	5,780	63,509	N/A	64.35
32	Total		2,192	148,166	9.1	64.4	32.6	13,348				1,589,635	7,602,180	5.13	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil
(3) Represents the portion of Gulf's 25% ownership available to the native load customers

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: NOVEMBER 2016

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	0	0.0	3.2	0.0	N/A	Coal	0	0	0	0	N/A	N/A
2	4								Gas - G	0	0	0	0		
3									Gas - S	0	0	0	0		
4									Oil - S	0	0	0	0		
5	Crist 5		75	0	0.0	12.6	0.0	N/A	Coal	0	0	0	0	N/A	N/A
6	5								Gas - G	0	0	0	0		
7									Gas - S	0	0	0	0		
8									Oil - S	0	0	0	0		
9	Crist 6		299	0	0.0	3.2	0.0	N/A	Coal	0	0	0	0	N/A	N/A
10	6								Gas - G	0	0	0	0		
11									Gas - S	0	0	0	0		
12									Oil - S	0	0	0	0		
13	Crist 7		475	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
14	7								Gas - G	0	0	0	0		
15									Gas - S	0	0	0	0		
16									Oil - S	0	0	0	0		
17	Smith 1		0	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
18									Oil - S	0	0	0	0		
19	Smith 2		0	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
20									Oil - S	0	0	0	0		
21	Smith 3		558	315,132	78.3	86.9	91.4	7,095	Gas - G	2,191,901	1,020	2,235,740	7,825,981	2.48	3.57
22	Smith A (CT)	(2)	36	0	0.0	98.3	0.0	N/A	Oil	0	0	0	0	N/A	N/A
23	Scherer 3	(3)	164	72,141	61.1	96.9	12.6	11,187	Coal	47,493	8,496	807,014	2,042,554	2.83	43.01
24	Other Generation			5,536					Gas				170,952	3.09	N/A
25	Perdido			2,031					Landfill Gas				63,631	3.13	N/A
26	Daniel 1	(1)	255	8,895	4.8	96.5	17.8	11,598	Coal	5,366	9,612	103,167	312,288	3.51	58.20
27									Oil - S	0	0	0	0		
28	Daniel 2	(1)	255	11,260	6.1	96.5	21.9	11,122	Coal	6,514	9,612	125,229	379,070	3.37	58.19
29									Oil - S	0	0	0	0		
30	Gas,BL								Gas	0	1,020	0	293,141	N/A	N/A
31	Ltr. Oil								Oil	586	139,400	3,430	37,224	N/A	63.52
32	Total		2,192	414,995	26.3	54.4	28.8	8,175				3,274,580	11,124,841	2.68	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil
(3) Represents the portion of Gulf's 25% ownership available to the native load customers

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF: DECEMBER 2016

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	2,697	4.8	88.3	74.9	10,980	Coal	1,250	11,850	29,614	94,616	3.51	75.69
2	4								Gas - G	0	0	0	0		
3									Gas - S	0	0	0	0		
4									Oil - S	0	0	0	0		
5	Crist 5		75	2,722	4.9	79.2	75.6	10,886	Coal	1,250	11,850	29,633	94,674	3.48	75.74
6	5								Gas - G	0	0	0	0		
7									Gas - S	0	0	0	0		
8									Oil - S	0	0	0	0		
9	Crist 6		299	31,132	14.0	87.8	70.8	10,758	Coal	14,131	11,850	334,909	1,070,009	3.44	75.72
10	6								Gas - G	0	0	0	0		
11									Gas - S	0	0	0	0		
12									Oil - S	0	0	0	0		
13	Crist 7		475	0	0.0	100.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
14	7								Gas - G	0	0	0	0		
15									Gas - S	0	0	0	0		
16									Oil - S	0	0	0	0		
17	Smith 1		0	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
18									Oil - S	0	0	0	0		
19	Smith 2		0	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
20									Oil - S	0	0	0	0		
21	Smith 3		584	372,730	85.8	96.5	89.3	7,056	Gas - G	2,578,347	1,020	2,629,914	9,686,911	2.60	3.76
22	Smith A (CT)	(2)	40	0	0.0	98.4	0.0	N/A	Oil	0	0	0	0	N/A	N/A
23	Scherer 3	(3)	164	73,495	60.3	96.9	12.8	11,190	Coal	48,411	8,494	822,401	2,082,332	2.83	43.01
24	Other Generation			5,720					Gas				176,634	3.09	N/A
25	Perdido			2,100					Landfill Gas				65,793	3.13	N/A
26	Daniel 1	(1)	255	23,480	12.4	96.5	0.0	10,605	Coal	13,105	9,500	249,008	746,917	3.18	56.99
27									Oil - S	0	0	0	0		
28	Daniel 2	(1)	255	23,437	12.4	96.5	28.4	10,635	Coal	13,118	9,500	249,249	747,640	3.19	56.99
29									Oil - S	0	0	0	0		
30	Gas,BL								Gas	14,706	1,020	15,000	337,424	N/A	22.94
31	Ltr. Oil								Oil	944	139,400	5,530	61,381	N/A	65.02
32	Total		2,222	537,513	32.5	95.3	42.3	8,588				4,365,258	15,164,331	2.82	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil
(3) Represents the portion of Gulf's 25% ownership available to the native load customers

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2016 - JUNE 2016 / ESTIMATED FOR JULY 2016 - DECEMBER 2016

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) (bs./cf/Gal.)	(k) Fuel Burned (MMBtu)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ kWh (¢/kWh)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		75	28,004	4.3	88.1	29.4	13,469	Coal	16,279	11,585	377,192	1,345,094	4.80	82.63
2	4								Gas - G	11,383	1,019	11,599	48,688	0.00	4.28
3									Gas - S	4,689	1,020	4,784	72,352		15.43
4									Oil - S	276	138,458	1,605	25,735		93.24
5	Crist 5		75	26,341	4.0	88.1	28.0	14,384	Coal	16,350	11,587	378,890	1,351,933	5.13	82.69
6	5								Gas - G	0	0	0	0	0.00	0.00
7									Gas - S	10,711	1,019	10,914	241,581		22.55
8									Oil - S	390	138,217	2,264	39,488		101.25
9	Crist 6		299	450,714	17.2	81.0	49.3	11,023	Coal	214,042	11,605	4,968,127	17,469,961	3.88	81.62
10	6								Gas - G	122,819	1,019	125,153	525,336	0.00	4.28
11									Gas - S	35,922	1,021	36,665	511,492		14.24
12									Oil - S	1,683	138,613	9,798	122,740		72.93
13	Crist 7		475	1,458,465	35.0	78.7	47.2	10,790	Coal	675,963	11,641	15,737,237	54,854,522	3.76	81.15
14	7								Gas - G	12,149	1,019	12,380	250,731	0.00	20.64
15									Gas - S	55,194	1,020	56,303	625,294		11.33
16									Oil - S	1,038	138,430	6,035	95,344		91.85
17	Smith 1		162	55,657	7.9	42.0	9.1	11,641	Coal	30,436	10,644	647,906	2,372,581	4.26	77.95
18									Oil - S	1,547	138,332	8,988	85,986		
19	Smith 2		195	(1,743)	(0.2)	50.0	0.0	0	Coal	0	0	0	0	0.00	N/A
20									Oil - S	0	0	0	0		
21	Smith 3		564	3,529,217	71.2	82.2	85.6	7,188	Gas - G	24,861,811	510	25,368,784	85,376,691	2.42	3.43
22	Smith A (CT)	(2)	36	190	0.1	98.2	30.1	21,068	Oil - G	689	138,330	4,003	71,368	37.56	103.58
23	Scherer 3	(3)	164	469,861	64.9	96.9	13.5	11,197	Coal	309,199	8,508	5,261,037	13,298,250	2.83	43.01
24	Other Generation			76,850					Gas				2,373,097	3.09	N/A
25	Perdido			24,047					Landfill Gas				753,444	3.13	N/A
26	Daniel 1	(1)	255	362,075	16.2	96.9	22.5	11,365	Coal	207,849	9,899	4,114,881	13,518,506	3.73	65.04
27									Oil - S	4,596	138,594	26,753	250,699		54.55
28	Daniel 2	(1)	255	379,846	17.0	96.8	27.3	11,459	Coal	231,836	9,387	4,352,715	15,312,841	4.03	66.05
29									Oil - S	1,442	138,581	8,393	78,242		54.26
30	Gas,BL								Gas	73,530	1,020	75,000	1,944,137	N/A	26.44
31	Ltr. Oil								Oil	5,102	139,441	29,880	323,948	N/A	63.49
32	Total		2,555	6,859,524	30.6	80.8	42.0	9,600				61,637,286	213,340,081	3.11	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Smith A uses lighter oil
(3) Represents the portion of Gulf's 25% ownership available serve the native load customers

Inventory Adjustments	$	units
COAL Daniel	(187,509)	(2,470)
Oil Daniel	0	0
Oil Smith	(26,021)	0
Total Adjustments	$ (213,530)	(2,470)
Total Fuel Burned Cost	**$ 213,126,551**	

Docket No. 160001-EI
2016 Est/Act True-Up Filing
Exhibit CSB-2, Page 20 of 33

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2016 - JUNE 2016 / ESTIMATED FOR JULY 2016 - DECEMBER 2016

		JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	JULY EST MATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL
	LIGHT OIL													
1	*PURCHASES :*													
2	UNITS (BBL)	3,925	2,213	0	0	4,156	613	604	912	724	960	583	942	15,632
3	UNIT COST ($/BBL)	43 55	48.79	0	0	60.26	65 83	65 97	66.00	65.92	66.20	66.30	66 29	58.49
4	AMOUNT ($)	170,924	107,972	195	32,053	250,460	40,352	39,843	60,192	47,729	63,553	38,654	62,447	914,374
5	*BURNED :*													
6	UNITS (BBL)	4,655	1,501	135	1,689	1,791	1,426	799	987	799	987	586	944	16,299
7	UNIT COST ($/BBL)	59 26	61.09	109.73	74.24	63.23	62 93	61.33	63.14	63.22	6.44	63.52	65 02	59.97
8	AMOUNT ($)	275,847	91,691	14,813	125,389	113,248	89,741	49,002	62,321	50,511	6,359	37,224	61,381	977,527
9	*ENDING INVENTORY :*													
10	UNITS (BBL)	3,641	4,353	4,218	2,529	5,423	4,610	4,415	4,340	4,265	4,238	4,235	4,233	
11	UNIT COST ($/BBL)	77 09	68.22	66.94	74.73	60.15	60 05	60.63	61.18	61.61	75.50	75.89	76.17	
12	AMOUNT ($)	280,677	296,958	282,339	189,004	326,216	276,827	267,668	265,539	262,757	319,951	321,381	322,447	
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 PLANT SCHERER													
14	*PURCHASES :*													
15	UNITS (TONS)	97,069	44,714	6,487	47,726	89,241	128,808	190,800	208,300	180,500	60,550	54,000	64,000	1,172,195
16	UNIT COST ($/TON)	88 94	100.19	239.50	95.08	89.10	81 89	65.12	64.65	65.09	62.95	58.67	59 84	73.50
17	AMOUNT ($)	8,633,691	4,479,872	1,553,616	4,537,991	7,951,279	10,548,492	12,425,808	13,466,691	11,748,965	3,811,408	3,168,110	3,829,784	86,155,707
18	*BURNED :*													
19	UNITS (TONS)	182,589	114,070	186	89,269	114,846	260,331	193,640	202,099	144,521	34,001	11,880	42,854	1,390,286
20	UNIT COST ($/TON)	78 99	78.30	412.65	86.68	84.92	80 54	73.48	70.31	69.46	66.18	58.20	64 26	76.29
21	AMOUNT ($)	14,423,618	8,931,854	76,752	7,737,578	9,752,875	20,966,809	14,229,243	14,209,801	10,038,042	2,250,272	691,358	2,753,856	106,062,058
22	*ENDING INVENTORY :*													
23	UNITS (TONS)	613,525	544,169	550,470	508,928	483,322	351,800	348,960	355,161	391,140	417,689	459,809	480,955	
24	UNIT COST ($/TON)	74.63	75.96	77.77	77.83	78.23	77 86	73 33	69.96	67.90	67.32	66.54	65 85	
25	AMOUNT ($)	45,787,030	41,335,048	42,811,912	39,612,325	37,810,728	27,392,410	25,588,975	24,845,865	26,556,788	28,117,924	30,594,676	31,670,604	
26	DAYS SUPPLY:	29	27	25	27	25	21	22	22	25	26	29	30	

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2016 - JUNE 2016 / ESTIMATED FOR JULY 2016 - DECEMBER 2016

		JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	JULY EST MATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL
	COAL at Plant Scherer													
1	*PURCHASES :*													
2	UNITS (MMBTU)	0	0	0	0	0	0	696,754	655,454	643,131	670,456	669,273	664,052	3,999,120
3	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0 00	2.54	2.54	2.54	2.54	2.53	2 54	2.54
4	AMOUNT ($)	0	0	0	0	0	0	1,767,298	1,665,068	1,632,202	1,703,861	1,695,223	1,683,706	10,147,358
5	*BURNED :*													
6	UNITS (MMBTU)	0	0	0	0	0	0	966,295	962,696	870,845	831,788	807,015	822,402	5,261,041
7	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0 00	2.52	2.53	2.53	2.53	2.53	2 53	2.53
8	AMOUNT ($)	0	0	0	0	0	0	2,436,668	2,430,825	2,201,066	2,104,805	2,042,554	2,082,332	13,298,250
9	*ENDING INVENTORY :*													
10	UNITS (MMBTU)	0	0	0	0	0	0	3,141,338	2,834,096	2,606,382	2,445,050	2,307,309	2,148,959	
11	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0 00	2.52	2.53	2.53	2.53	2.53	2 53	
12	AMOUNT ($)	0	0	0	0	0	0	7,922,711	7,156,954	6,588,090	6,187,146	5,839,815	5,441,189	
13	DAYS SUPPLY:	0	0	0	0	0	0	59	53	49	46	43	40	
	GAS (Reported on a MMBTU and $ basis)													
14	*BURNED :*													
15	UNITS (MMBTU)	2,364,046	2,213,774	2,847,231	2,551,440	1,872,031	2,522,431	2,631,031	2,618,985	1,139,959	0	2,235,740	2,629,914	25,626,582
16	UNIT COST ($/MMBTU)	3.03	2.75	2.36	2.84	3.21	3 59	3.74	3.72	4.99	0.00	3.50	3.68	3.42
17	AMOUNT ($)	7,174,435	6,084,920	6,723,828	7,238,256	6,001,154	9,056,099	9,834,569	9,741,206	5,685,103	2,599,234	7,825,981	9,686,911	87,651,696
	OTHER - C.T. OIL													
18	*PURCHASES :*													
19	UNITS (BBL)	0	173	0	0	531	0	0	0	0	0	0	0	704
20	UNIT COST ($/BBL)	0.00	104.77	0.00	0.00	60.92	0 00	0.00	0.00	0.00	0.00	0.00	0 00	71.70
21	AMOUNT ($)	0	18,126	0	0	32,348	0	0	0	0	0	0	0	50,474
22	*BURNED :*													
23	UNITS (BBL)	0	110	104	239	160	76	0	0	0	0	0	0	689
24	UNIT COST ($/BBL)	0 00	104.67	104.38	104.61	101.52	102 03	0.00	0.00	0.00	0.00	0.00	0 00	103.58
25	AMOUNT ($)	0	11,514	10,855	25,002	16,243	7,754	0	0	0	0	0	0	71,368
26	*ENDING INVENTORY :*													
27	UNITS (BBL)	6,733	6,976	6,693	6,454	6,826	6,749	6,749	6,749	6,749	6,749	6,749	6,749	
28	UNIT COST ($/BBL)	104 83	102.13	104.83	104.83	101.48	101.49	101.49	101.49	101.49	101.49	101.49	101.49	
29	AMOUNT ($)	705,847	712,459	701,604	676,603	692,709	684,955	684,955	684,955	684,955	684,955	684,955	684,955	
30	HOURS SUPPLY:	76	79	76	73	77	76	76	76	76	76	76	76	

(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.

SCHEDULE E-6
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POWER SOLD
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2016 - JUNE 2016 / ESTIMATED FOR JULY 2016 - DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
						(A)	(B)		
				KWH		¢ / KWH			
	MONTH		TOTAL	WHEELED	KWH	FUEL	TOTAL	TOTAL $	
LINE		TYPE & SCHEDULE	KWH SOLD	FROM OTHER SYSTEMS	FROM OWN GENERATION	COST	COST	FOR FUEL ADJUSTMENT	TOTAL COST $
	JANUARY								
1		Other Power Sales	646,693,539	154,139,961	492,553,578	1.31	1.50	8,478,980	9,693,223
2		Economy Sales	8,111,533	0	8,111,533	2.00	2.65	162,552	214,587
3		Gain on Economy Sales	0	0	0	0.00	0.00	7,884	7,884
4		TOTAL ACTUAL SALES	654,805,072	154,139,961	500,665,111	1.32	1.51	8,649,416	9,915,694
	FEBRUARY								
5		Other Power Sales	479,379,888	126,803,196	352,576,692	0.88	0.99	4,225,998	4,758,493
6		Economy Sales	13,963,426	0	13,963,426	1.64	2.25	229,286	314,238
7		Gain on Economy Sales	0	0	0	0.00	0.00	74,941	74,941
8		TOTAL ACTUAL SALES	493,343,314	126,803,196	366,540,118	0.92	1.04	4,530,225	5,147,672
	MARCH								
9		Other Power Sales	558,493,203	113,435,476	445,057,727	1.01	1.16	5,642,109	6,481,068
10		Economy Sales	5,366,623	0	5,366,623	2.12	2.36	113,945	126,666
11		Gain on Economy Sales	0	0	0	0.00	0.00	(1,481)	(1,481)
12		TOTAL ACTUAL SALES	563,859,826	113,435,476	450,424,350	1.02	1.17	5,754,573	6,606,253
	APRIL								
13		Other Power Sales	351,968,686	100,628,659	251,340,027	0.90	1.03	3,164,594	3,622,630
14		Economy Sales	9,627,486	0	9,627,486	1.68	2.65	161,483	254,775
15		Gain on Economy Sales	0	0	0	0.00	0.00	55,770	55,770
16		TOTAL ACTUAL SALES	361,596,172	100,628,659	260,967,513	0.94	1.09	3,381,847	3,933,175
	MAY								
17		Other Power Sales	378,016,514	120,020,413	257,996,101	0.61	0.69	2,309,334	2,594,305
18		Economy Sales	6,159,991	0	6,159,991	1.70	2.37	104,527	145,802
19		Gain on Economy Sales	0	0	0	0.00	0.00	2,243	2,243
20		TOTAL ACTUAL SALES	384,176,505	120,020,413	264,156,092	0.63	0.71	2,416,104	2,742,350
	JUNE								
21		Other Power Sales	546,157,626	127,808,748	418,348,878	1.28	1.49	7,002,577	8,111,829
22		Economy Sales	8,395,912	0	8,395,912	2.46	3.59	206,749	301,679
23		Gain on Economy Sales	0	0	0	0.00	0.00	36,594	36,594
24		TOTAL ACTUAL SALES	554,553,538	127,808,748	426,744,790	1.31	1.52	7,245,920	8,450,102

SCHEDULE E-6
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POWER SOLD
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2016 - JUNE 2016 / ESTIMATED FOR JULY 2016 - DECEMBER 2016

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
			KWH		(A) (B)			
		TOTAL	WHEELED	KWH	¢ / KWH		TOTAL $	
	MONTH	KWH	FROM OTHER	FROM OWN	FUEL	TOTAL	FOR FUEL	TOTAL COST
LINE	TYPE & SCHEDULE	SOLD	SYSTEMS	GENERATION	COST	COST	ADJUSTMENT	$
	JULY							
1	Other Power Sales	287,458,000	0	287,458,000	2.16	2.76	6,201,000	7,940,000
2	Economy Sales	10,867,000	0	10,867,000	2.26	2.76	246,000	300,000
3	Gain on Economy Sales	0	0	0	0.00	0.00	75,000	75,000
4	TOTAL ESTIMATED SALES	298,325,000	0	298,325,000	2.19	2.79	6,522,000	8,315,000
	AUGUST							
5	Other Power Sales	286,833,000	0	286,833,000	2.36	2.79	6,775,000	8,010,000
6	Economy Sales	8,802,000	0	8,802,000	2.35	2.72	207,000	239,000
7	Gain on Economy Sales	0	0	0	0.00	0.00	77,000	77,000
8	TOTAL ESTIMATED SALES	295,635,000	0	295,635,000	2.39	2.82	7,059,000	8,326,000
	SEPTEMBER							
9	Other Power Sales	131,745,000	0	131,745,000	2.23	2.61	2,943,000	3,436,000
10	Economy Sales	7,503,000	0	7,503,000	2.37	2.71	178,000	203,000
11	Gain on Economy Sales	0	0	0	0.00	0.00	53,000	53,000
12	TOTAL ESTIMATED SALES	139,248,000	0	139,248,000	2.28	2.65	3,174,000	3,692,000
	OCTOBER							
13	Other Power Sales	18,108,000	0	18,108,000	1.82	2.14	329,000	387,000
14	Economy Sales	11,913,000	0	11,913,000	2.13	2.49	254,000	297,000
15	Gain on Economy Sales	0	0	0	0.00	0.00	33,000	33,000
16	TOTAL ESTIMATED SALES	30,021,000	0	30,021,000	2.05	2.39	616,000	717,000
	NOVEMBER							
17	Other Power Sales	9,914,000	0	9,914,000	2.10	2.50	208,000	248,000
18	Economy Sales	12,024,000	0	12,024,000	2.16	2.54	260,000	306,000
19	Gain on Economy Sales	0	0	0	0.00	0.00	29,000	29,000
20	TOTAL ESTIMATED SALES	21,938,000	0	21,938,000	2.27	2.66	497,000	583,000
	DECEMBER							
21	Other Power Sales	123,675,000	0	123,675,000	2.13	2.51	2,634,000	3,100,000
22	Economy Sales	10,994,000	0	10,994,000	2.13	2.60	234,000	286,000
23	Gain on Economy Sales	0	0	0	0.00	0.00	47,000	47,000
24	TOTAL ESTIMATED SALES	134,669,000	0	134,669,000	2.16	2.55	2,915,000	3,433,000
	TOTAL							
25	Other Power Sales	3,818,442,456	742,836,453	3,075,606,003	1.31	1.53	49,913,592	58,382,548
26	Economy Sales	113,727,971	0	113,727,971	2.07	2.63	2,357,542	2,988,747
27	Gain on Economy Sales	0	0	0	0.00	0.00	489,951	489,951
28	TOTAL ESTIMATED SALES	3,932,170,427	742,836,453	3,189,333,974	1.34	1.57	52,761,085	61,861,246

SCHEDULE E-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ACTUAL FOR THE PERIOD JANUARY 2016 - JUNE 2016 / ESTIMATED FOR JULY 2016 - DECEMBER 2016

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) ¢ / KWH		(9)
MONTH	PURCHASED FROM	TYPE & SCHED	TOTAL KWH PURCH.	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
January	NONE								
February	NONE								
March	NONE								
April	NONE								
May	NONE								
June	NONE								
July	NONE								
August	NONE								
September	NONE								
October	NONE								
November	NONE								
December	NONE								
Total	NONE								

SCHEDULE E-8

ENERGY PAYMENT TO QUALIFYING FACILITIES
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2016 - JUNE 2016 / ESTIMATED FOR JULY 2016 - DECEMBER 2016

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				KWH			¢/KWH		
MONTH	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
JANUARY	Total		21,561,000	0	0	0	2.67	2.67	574,811
FEBRUARY	Total		17,832,000	0	0	0	2.12	2.12	377,155
MARCH	Total		12,294,000	0	0	0	2.81	2.81	345,591
APRIL	Total		18,090,000	0	0	0	2.52	2.52	456,595
MAY	Total		21,405,000	0	0	0	2.42	2.42	517,023
JUNE	Total		22,327,000	0	0	0	2.83	2.83	632,540
JULY	Total		11,828,000	0	0	0	2.93	2.93	346,000
AUGUST	Total		11,828,000	0	0	0	2.93	2.93	346,000
SEPTEMBER	Total		11,826,000	0	0	0	2.93	2.93	346,000
OCTOBER	Total		13,731,000	0	0	0	2.93	2.93	402,000
NOVEMBER	Total		13,730,000	0	0	0	2.59	2.59	355,000
DECEMBER	Total		13,731,000	0	0	0	2.59	2.59	355,000
TOTAL			190,183,000	0	0	0	2.66	2.66	5,053,715

SCHEDULE E-9
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ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2016 - JUNE 2016 / ESTIMATED FOR JULY 2016 - DECEMBER 2016

	(1)	(2)	(3)	(4)	(5)
LINE	MONTH	TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JANUARY				
1		Southern Co. Interchange	118,621,370	2.48	2,937,300
2		Other Purchases	803,279,452	1.45	11,683,578
3		TOTAL ACTUAL PURCHASES	921,900,822	1.59	14,620,878
	FEBRUARY				
4		Southern Co. Interchange	99,756,282	1.69	1,688,848
5		Other Purchases	674,825,032	1.38	9,333,188
6		TOTAL ACTUAL PURCHASES	774,581,314	1.42	11,022,036
	MARCH				
7		Southern Co. Interchange	67,403,408	2.19	1,476,877
8		Other Purchases	920,975,918	1.41	12,973,676
9		TOTAL ACTUAL PURCHASES	988,379,326	1.46	14,450,553
	APRIL				
10		Southern Co. Interchange	104,179,580	2.33	2,429,318
11		Other Purchases	531,573,592	1.46	7,750,690
12		TOTAL ACTUAL PURCHASES	635,753,172	1.60	10,180,008
	MAY				
13		Southern Co. Interchange	143,772,880	1.98	2,849,683
14		Other Purchases	773,680,875	1.44	11,162,129
15		TOTAL ACTUAL PURCHASES	917,453,755	1.53	14,011,812
	JUNE				
16		Southern Co. Interchange	86,781,279	2.84	2,462,105
17		Other Purchases	797,635,259	1.72	13,679,679
18		TOTAL ACTUAL PURCHASES	884,416,538	1.83	16,141,784

SCHEDULE E-9
Page 2 of 2

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2016 - JUNE 2016 / ESTIMATED FOR JULY 2016 - DECEMBER 2016

(1)	(2)	(3)	(4)	(5)
LINE	MONTH TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JULY			
1	Southern Co. Interchange	52,048,000	2.80	1,459,000
2	Other Purchases	631,071,000	2.33	14,706,000
3	TOTAL ESTIMATED PURCHASES	683,119,000	2.37	16,165,000
	AUGUST			
4	Southern Co. Interchange	18,145,000	2.60	472,000
5	Other Purchases	642,914,000	2.40	15,438,000
6	TOTAL ESTIMATED PURCHASES	661,059,000	2.41	15,910,000
	SEPTEMBER			
7	Southern Co. Interchange	67,011,000	2.76	1,847,000
8	Other Purchases	616,113,000	2.45	15,100,000
9	TOTAL ESTIMATED PURCHASES	683,124,000	2.48	16,947,000
	OCTOBER			
10	Southern Co. Interchange	291,235,000	2.67	7,785,000
11	Other Purchases	488,730,000	2.58	12,630,000
12	TOTAL ESTIMATED PURCHASES	779,965,000	2.62	20,415,000
	NOVEMBER			
13	Southern Co. Interchange	279,034,000	2.50	6,988,000
14	Other Purchases	114,463,000	5.62	6,431,000
15	TOTAL ESTIMATED PURCHASES	393,497,000	3.41	13,419,000
	DECEMBER			
16	Southern Co. Interchange	63,547,000	2.31	1,470,000
17	Other Purchases	421,071,000	2.99	12,576,000
18	TOTAL ESTIMATED PURCHASES	484,618,000	2.90	14,046,000
	TOTAL FOR PERIOD			
19	Southern Co. Interchange	1,391,534,799	2.43	33,865,131
20	Other Purchases	7,416,332,128	1.93	143,463,940
21	TOTAL ACT/EST PURCHASES	8,807,866,927	2.01	177,329,071

Schedule CCE-1A

PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
TO BE INCLUDED IN THE PERIOD JANUARY 2017 - DECEMBER 2017

1.	Estimated over/(under)-recovery, January 2016 - December 2016 (Schedule CCE-1b, line 15 + 18)	$	149,231
2.	Final over/(under)-recovery, January 2015 - December 2015 (Exhibit CSB-1, Schedule CCA-1, filed March 2, 2016)		(965,767)
3.	Total Over/(Under)-Recovery (Line 1 + 2) (To be included in January 2017 - December 2017)	$	(816,536)
4.	Jurisdictional kWh sales, January 2017 - December 2017		11,022,525,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢/kWh)		0.0074

SCHEDULE CCE-1B

Purchased Power Capacity Cost Recovery Clause
Calculation of Estimated True-Up Amount
Gulf Power Company
For the Period January 2016 - December 2016

		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projection August	Projection September	Projection October	Projection November	Projection December	Total
1	IIC Payments/(Receipts) ($)	(31,479)	(13,056)	(38,017)	16,919	(9,402)	(14,270)	0	0	0	0	0	0	(89,305)
2	Other Capacity Payments / (Receipts)	7,386,547	7,386,547	7,386,547	7,385,880	7,435,880	7,402,529	7,198,087	7,198,087	7,198,087	7,198,087	7,198,087	7,185,442	87,559,807
3	Transmission Revenue	(10,822)	(10,717)	(11,030)	(11,835)	(10,032)	(16,929)	(11,000)	(9,000)	(8,000)	(12,000)	(12,000)	(11,000)	(134,365)
4	Total Capacity Payments/(Receipts)	7,344,246	7,362,774	7,337,500	7,390,964	7,416,446	7,371,330	7,187,087	7,189,087	7,190,087	7,186,087	7,186,087	7,174,442	87,336,137
5	Jurisdictional %	0.9707146	0.9707146	0.9707146	0.9707146	0 9707146	0 9707146	0.9707146	0.9707146	0.9707146	0.9707146	0 9707146	0 9707146	
6	Jurisdictional Capacity Payments/(Receipts) (Line 4 x Line 5) ($)	7,129,167	7,147,152	7,122,618	7,174,517	7,199,252	7,155,458	6,976,610	6,978,552	6,979,522	6,975,640	6,975,640	6,964,336	84,778,464
7	Retail KWH Sales							1,179,840,000	1,166,950,000	1,021,925,000	839,139,000	734,554,000	826,023,000	
8	Purchased Power Capacity Cost Recovery Factor (¢/KWH)							0.775	0.775	0.775	0.775	0.775	0.775	
9	Capacity Cost Recovery Revenues (Line 7 x Line 8/100) ($)	7,003,282	5,860,819	5,737,058	5,697,267	7,358,473	8,615,382	9,143,760	9,043,863	7,919,919	6,503,327	5,692,794	6,401,678	84,977,622
10	Revenue Taxes (Line 9 x .00072) ($)	5,042	4,220	4,131	4,102	5,298	6,203	6,584	6,512	5,702	4,682	4,099	4,609	61,184
11	True-Up Provision ($)	1,491	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	17,859
12	Capacity Cost Recovery Revenues net of Revenue Taxes (Line 9 - Line 10 + Line 11) ($)	6,999,731	5,858,087	5,734,415	5,694,653	7,354,663	8,610,667	9,138,664	9,038,839	7,915,705	6,500,133	5,690,183	6,398,557	84,934,297
13	Over/(Under) Recovery (Line 12 - Line 6) ($)	(129,436)	(1,289,065)	(1,388,203)	(1,479,864)	155,411	1,455,209	2,162,054	2,060,287	936,183	(475,507)	(1,285,457)	(565,779)	155,833
14	Interest Provision ($)	(337)	(590)	(1,097)	(1,463)	(1,509)	(1,344)	(811)	(143)	332	404	125	(169)	(6,602)
15	Total Estimated True-Up for the Period January 2016 - December 2016 (Line 13 + Line 14) ($)													149,231
16	Beginning Balance True-Up & Interest Provision ($)	(947,908)	(1,079,172)	(2,370,315)	(3,761,103)	(5,243,918)	(5,091,504)	(3,639,127)	(1,479,372)	579,284	1,514,311	1,037,720	(249,100)	(947,908)
17	True-Up Collected/(Refunded) ($)	(1,491)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(17,859)
18	Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
19	End of Period TOTAL Net True-Up (Lines 13 + 14 + 16 + 17 + 18) ($)	(1,079,172)	(2,370,315)	(3,761,103)	(5,243,918)	(5,091,504)	(3,639,127)	(1,479,372)	579,284	1,514,311	1,037,720	(249,100)	(816,536)	

SCHEDULE CCE-2

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP AND INTEREST PROVISION
FOR THE PERIOD JANUARY 2016 - DECEMBER 2016

		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	Total
1.	IIC Payments / (Receipts) ($)	(31,479)	(13,056)	(38,017)	16,919	(9,402)	(14,270)	0	0	0	0	0	0	(89,305)
2.	Other Capacity Payments / (Receipts)	7,386,547	7,386,547	7,386,547	7,385,880	7,435,880	7,402,529	7,198,087	7,198,087	7,198,087	7,198,087	7,198,087	7,185,442	87,559,807
3.	Transmission Revenue ($)	(10,822)	(10,717)	(11,030)	(11,835)	(10,032)	(16,929)	(11,000)	(9,000)	(8,000)	(12,000)	(12,000)	(11,000)	(134,365)
4.	Total Capacity Payments/(Receipts) (Line 1 + 2 + 3) ($)	7,344,246	7,362,774	7,337,500	7,390,964	7,416,446	7,371,330	7,187,087	7,189,087	7,190,087	7,186,087	7,186,087	7,174,442	87,336,137
5.	Jurisdictional %	0.9707146	0 9707146	0.9707146	0 9707146	0.9707146	0 9707146	0.9707146	0 9707146	0.9707146	0.9707146	0.9707146	0.9707146	
6.	Total Jurisdictional Recovery Amount (Line 4 * 5) ($)	7,129,167	7,147,152	7,122,618	7,174,517	7,199,252	7,155,458	6,976,610	6,978,552	6,979,522	6,975,640	6,975,640	6,964,336	84,778,464
7.	Jurisdictional Capacity Cost Recovery Revenues Net of Taxes ($)	6,998,240	5,856,599	5,732,927	5,693,165	7,353,175	8,609,179	9,137,176	9,037,351	7,914,217	6,498,645	5,688,695	6,397,069	84,916,438
8.	True-Up Provision ($)	1,491	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	17,859
9.	Jurisdictional Capacity Cost Recovery Revenue (Line 7 + 8) ($)	6,999,731	5,858,087	5,734,415	5,694,653	7,354,663	8,610,667	9,138,664	9,038,839	7,915,705	6,500,133	5,690,183	6,398,557	84,934,297
10.	Over/(Under) Recovery (Line 9 - 6) ($)	(129,436)	(1,289,065)	(1,388,203)	(1,479,864)	155,411	1,455,209	2,162,054	2,060,287	936,183	(475,507)	(1,285,457)	(565,779)	155,833
11.	Interest Provision ($)	(337)	(590)	(1,097)	(1,463)	(1,509)	(1,344)	(811)	(143)	332	404	125	(169)	(6,602)
12.	Beginning Balance True-Up & Interest Provision ($)	(947,908)	(1,079,172)	(2,370,315)	(3,761,103)	(5,243,918)	(5,091,504)	(3,639,127)	(1,479,372)	579,284	1,514,311	1,037,720	(249,100)	(947,908)
13.	True-Up Collected/(Refunded) ($)	(1,491)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(17,859)
14.	Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
15.	End of Period Total Net True-Up (Lines 10 + 11 + 12 + 13 + 14) ($)	(1,079,172)	(2,370,315)	(3,761,103)	(5,243,918)	(5,091,504)	(3,639,127)	(1,479,372)	579,284	1,514,311	1,037,720	(249,100)	(816,536)	(816,536)
	Average Monthly Interest Rate	0.0333%	0.0342%	0.0358%	0.0325%	0.0292%	0.0308%	0.0317%	0.0317%	0.0317%	0.0317%	0.0317%	0.0317%	
	Wall Street Annual Rate 0.40%	0.40%	0.42%	0.44%	0.34%	0.36%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	
	Average Annual Rate	0.400%	0.410%	0.430%	0.390%	0 350%	0.370%	0 380%	0.380%	0.380%	0.380%	0.380%	0.380%	

SCHEDULE CCE-3

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
FOR THE PERIOD JANUARY 2016 - DECEMBER 2016

	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	TOTAL
1. Beginning True-Up Amount ($)	(947,908)	(1,079,172)	(2,370,315)	(3,761,103)	(5,243,918)	(5,091,504)	(3,639,127)	(1,479,372)	579,284	1,514,311	1,037,720	(249,100)	
2. Ending True-Up Amount Before Interest ($)	(1,078,835)	(2,369,725)	(3,760,006)	(5,242,455)	(5,089,995)	(3,637,783)	(1,478,561)	579,427	1,513,979	1,037,316	(249,225)	(816,367)	
3. Total Beginning & Ending True-Up Amount ($) (Lines 1 + 2)	(2,026,743)	(3,448,897)	(6,130,321)	(9,003,558)	(10,333,913)	(8,729,287)	(5,117,688)	(899,945)	2,093,263	2,551,627	788,495	(1,065,467)	
4. Average True-Up Amount ($)	(1,013,372)	(1,724,449)	(3,065,161)	(4,501,779)	(5,166,957)	(4,364,644)	(2,558,844)	(449,973)	1,046,632	1,275,814	394,248	(532,734)	
5. Interest Rate - First Day of Reporting Business Month	0.40%	0.40%	0.42%	0.44%	0 34%	0.36%	0 38%	0.38%	0 38%	0.38%	0 38%	0.38%	
6. Interest Rate - First Day of Subsequent Business Month	0.40%	0.42%	0.44%	0.34%	0 36%	0.38%	0 38%	0.38%	0 38%	0.38%	0 38%	0.38%	
7. Total Interest Rate (Lines 5 + 6)	0.80%	0.82%	0.86%	0.78%	0.70%	0.74%	0.76%	0.76%	0.76%	0.76%	0.76%	0.76%	
8. Average Interest Rate	0.400%	0.410%	0.430%	0.390%	0.350%	0 370%	0.380%	0 380%	0.380%	0.380%	0.380%	0.380%	
9. Monthly Average Interest Rate (1/12 Of Line 8)	0.0333%	0.0342%	0.0358%	0.0325%	0.0292%	0.0308%	0.0317%	0.0317%	0.0317%	0.0317%	0.0317%	0.0317%	
10. Interest Provision For the Month (Lines 4 X 9) ($)	(337)	(590)	(1,097)	(1,463)	(1,509)	(1,344)	(811)	(143)	332	404	125	(169)	(6,602)

Gulf Power Company
2016 Capacity Contracts

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Term			Contract									
Contract/Counterparty	Start	End [1]		Type									
Southern Intercompany Interchange	5/1/2007	5 Yr Notice		SES Opco									
PPAs													
Shell Energy N.A. (U.S.), LP [2]	11/2/2009	5/31/2023		Firm									
Other													
Cargill Power, LLC	2/13/2016	2/14/2016		Other									
South Carolina PSA	9/1/2003	-		Other									
South Carolina Electric & Gas	1/1/2016	6/29/2016		Other									
The Electric Authority	1/5/2016	1/5/2016		Other									

Capacity Costs ($)	Actual January [1]	Actual February [1]	Actual March	Actual April	Actual May [1]	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	Total
Southern Intercompany Interchange	(17,016)	1,445	(23,747)	31,189	4,868	0	0	0	0	0	0	(12,645)	(15,906)
PPAs													
Shell Energy N.A. (U.S.), LP	[redacted]												
Other													
Cargill Power, LLC	[redacted]		0	-	0	0	0	0	0	0	0	[redacted]	
South Carolina PSA													
South Carolina Electric & Gas													
The Electric Authority		0	0	0	0	0	0	0	0	0	0	0	
Total	7,355,068	7,373,491	7,348,530	7,402,799	7,426,478	7,388,259	7,198,087	7,198,087	7,198,087	7,198,087	7,198,087	7,185,442	87,470,502

Capacity MW	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December
Southern Intercompany Interchange	(23.1)	0.0	(72.7)	157.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(77.5)
PPAs												
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
Other												
Cargill Power, LLC	0.0	[redacted]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Carolina PSA												
South Carolina Electric & Gas												
The Electric Authority		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

(1) Unless o herwise noted, contract remains effec ive unless terminated upon 30 days prior written notice.
(2) Contract megawatts became firm on June 1, 2014.

SCHEDULE E-1

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
PROPOSED FOR THE PERIOD: JANUARY 2017 - DECEMBER 2017

Line				$	kWh	¢ / kWh
1	Fuel Cost of System Net Generation		E-3	272,062,919	9,271,402,000	2.9344
2	Coal Car Investment			0		
3	Other Generation		E-3	2,514,497	81,428,000	3.0880
4	Hedging Settlement		E-2	0	0	N/A
5	**Total Cost of Generated Power**	(Line 1 - 4)		274,577,416	9,352,830,000	2.9358
6	Fuel Cost of Purchased Power (Exclusive of Economy)		E-7			
7	Energy Cost of Schedule C & X Econ. Purch.		E-9			
8	Energy Cost of Other Econ. Purch. (Nonbroker)		E-9	209,644,000	6,628,400,000	3.1628
9	Energy Cost of Schedule E Economy Purch.		E-9			
10	Capacity Cost of Schedule E Economy Purchases		E-2			
11	Energy Payments to Qualifying Facilities		E-8	4,260,000	158,882,000	2.6812
12	**Total Cost of Purchased Power**	(Line 6 - 11)		213,904,000	6,787,282,000	3.1515
13	**Total Available kWh**	(Line 5 + 12)			16,140,112,000	
14	Fuel Cost of Economy Sales		E-6	(3,113,000)	(136,467,000)	2.2811
15	Gain on Economy Sales		E-6	(557,000)	0	N/A
16	Fuel Cost of Other Power Sales		E-6	(102,114,000)	(4,018,534,000)	2.5411
17	**Total Fuel Cost & Gains on Power Sales**	(Line 14 -16)		(105,784,000)	(4,155,001,000)	2.5459
18	Net Inadvertant Interchange					
19	**Total Fuel & Net Power Trans.**	(Line 5+12+17+18)		382,697,416	11,985,111,000	3.1931
20	Net Unbilled Sales *					
21	Company Use *			660,908	20,698,000	3.1931
22	T & D Losses *			19,235,107	602,396,000	3.1931
23	**System kWh Sales**			382,697,416	11,362,017,000	3.3682
24	Wholesale kWh Sales			11,434,770	339,492,000	3.3682
25	Jurisdictional kWh Sales			371,262,646	11,022,525,000	3.3682
25a	Jurisdictional Line Loss Multiplier			1.0015		1.0015
26	Jurisdictional kWh Sales Adjusted for Line Losses			371,819,540	11,022,525,000	3.3733
27	**True-Up ****			(26,059,665)	11,022,525,000	(0.2364)
28	**Total Jurisdictional Fuel Cost**			345,759,875	11,022,525,000	3.1369
29	Revenue Tax Factor					1.00072
30	Fuel Factor Adjusted For Revenue Taxes			346,008,822	11,022,525,000	3.1391
31	GPIF Reward/(Penalty) **			(45,708)	11,022,525,000	(0.0004)
32	Fuel Factor Adjusted for GPIF			345,963,114	11,022,525,000	3.1387
33	**Fuel Factor Rounded to Nearest .001(¢ / kWh)**					**3.139**

*For informational purposes only
** Calculation Based on Jurisdictional kWh Sales

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 46
PARTY: GULF POWER COMPANY – (DIRECT)
DESCRIPTION: C. S. Boyett CSB-3

SCHEDULE E-1A

FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
TO BE INCLUDED IN THE PERIOD: JANUARY 2017 - DECEMBER 2017

1.	Estimated over/(under)-recovery, January 2016 - December 2016 (Schedule E-1B, page 2, line C9)	$27,383,731
2.	Final over/(under)-recovery, January 2015 - December 2015 (Exhibit CSB-1, Schedule 1, Line 3)	($1,324,066)
3.	Total over/(under)-recovery (Lines 1 + 2) To be included in January 2017 - December 2017 (Schedule E1, Line 27)	26,059,665
4.	Jurisdictional kWh sales For the period: January 2017 - December 2017	11,022,525,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢ / kWh)	(0.2364)

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2016 - JUNE 2016 / ESTIMATED FOR JULY 2016 - DECEMBER 2016

			JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	TOTAL SIX MONTHS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation	21,899,067.00	15,153,243.00	6,888,569.00	15,179,780.00	15,949,057.00	30,181,393.00	$105,251,108.43
	1a	Fuel Cost of Hedging Settlement	5,195,191.00	6,107,019.00	6,681,995.00	5,239,140.00	5,718,593.00	4,737,258.00	$33,679,196.00
	2	Fuel Cost of Power Sold	(8,649,415.54)	(4,530,225.28)	(5,754,573.44)	(3,381,847.31)	(2,416,103.49)	(7,245,919.54)	($31,978,085.20)
	3	Fuel Cost of Purchased Power	14,620,878.25	11,022,035.97	14,450,553.38	10,180,007.70	14,011,811.53	16,141,784.21	$80,427,071.04
	3a	Demand & Non-Fuel Cost of Purchased Power	0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	3b	Energy Payments to Qualified Facilities	574,810.71	377,155.48	345,590.67	456,594.55	517,022.76	632,540.33	$2,903,714.50
	4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation	197,027.00	143,006.00	173,299.00	175,595.00	182,292.00	192,072.00	$1,063,291.49
	6	Adjustments to Fuel Cost	0.00	4.77	11.37	2.78	7.56	19.95	$46.43
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)	33,837,558.87	28,272,239.45	22,785,444.68	27,849,272.68	33,962,680.05	44,639,147.56	$191,346,343.29
B	1	Jurisdictional KWH Sales	891,087,234	756,584,301	765,402,935	752,614,350	953,141,310	1,105,160,254	5,223,990,384
	2	Non-Jurisdictional KWH Sales	27,628,571	23,343,210	21,801,748	21,366,561	25,996,698	30,120,479	150,257,267
	3	TOTAL SALES (Lines B1 + B2)	918,715,805	779,927,511	787,204,683	773,980,911	979,138,008	1,135,280,733	$5,374,247,651.00
	4	Jurisdictional % of Total Sales (Line B1/B3)	96.9927%	97.0070%	97.2305%	97.2394%	97.3449%	97.3469%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes) **(1)**	31,733,646.00	26,696,738.00	27,092,412.00	26,701,932.00	33,711,744.00	41,860,632.00	$187,797,104.47
	2	True-Up Provision	1,614,173.00	1,614,174.00	1,614,174.00	1,614,174.00	1,614,174.00	1,614,174.00	$9,685,043.00
	2a	Incentive Provision	(220,533.00)	(220,534.00)	(220,534.00)	(220,534.00)	(220,534.00)	(220,534.00)	($1,323,203.00)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)	33,127,286.14	28,090,378.31	28,486,052.25	28,095,571.64	35,105,383.78	43,254,272.35	$196,158,944.47
	4	Fuel & Net Power Transactions (Line A7)	33,837,559.00	28,272,239.00	22,785,445.00	27,849,273.00	33,962,680.00	44,639,148.00	$191,346,343.29
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0015)	32,869,192.00	27,467,190.00	22,187,633.00	27,121,086.00	33,110,528.00	43,520,009.00	$186,275,638.98
	6	Over/(Under) Recovery (Line C3-C5)	258,094.23	623,187.91	6,298,418.86	974,485.28	1,994,855.44	(265,736.23)	$9,883,305.49
	7	Interest Provision	5,783.54	5,540.48	6,449.19	6,501.73	5,805.64	5,894.66	$35,975.24
	8	Adjustments **(2)**	0.00	0.00	(75,803.69)	0.00	0.00	0.00	($75,803.69)
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2016 - JUNE 2016**							$9,843,477.04

* (Gain)/Loss on sales of natural gas

Notes 1: Projected Revenues based on the current approved 2016 Fuel Factor excluding revenue taxes of: 3.6474 ¢/kWh
2: Audit finding adjustment
3: January - June Scherer adjustment

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2016 - JUNE 2016 / ESTIMATED FOR JULY 2016 - DECEMBER 2016

			JULY PROJECTION	AUGUST PROJECTION	SEPTEMBER PROJECTION	OCTOBER PROJECTION	NOVEMBER PROJECTION	DECEMBER PROJECTION	TOTAL PERIOD
			(a)	(a)	(c)	(d)	(e)	(f)	(g)
A	1 Fuel Cost of System Generation		26,930,726.00	26,849,391.00	18,355,096.00	7,425,546.00	10,953,889.00	14,987,697.00	$210,753,453.43
	1a Fuel Cost of Hedging Settlement		3,983,180.00	4,055,860.00	3,983,814.00	3,719,065.00	3,017,580.00	2,287,103.00	$54,725,798.00
	2 Fuel Cost of Power Sold		(6,522,000.00)	(7,059,000.00)	(3,174,000.00)	(616,000.00)	(497,000.00)	(2,915,000.00)	($52,761,085.20)
	3 Fuel Cost of Purchased Power		16,165,000.00	15,910,000.00	16,947,000.00	20,415,000.00	13,419,000.00	14,046,000.00	$177,329,071.04
	3a Demand & Non-Fuel Cost Of Purchased Power		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	3b Energy Payments to Qualified Facilities		346,000.00	346,000.00	346,000.00	402,000.00	355,000.00	355,000.00	$5,053,714.50
	4 Energy Cost of Economy Purchases		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5 Other Generation		264,703.00	264,703.00	256,180.00	176,634.00	170,952.00	176,634.00	$2,373,097.49
	6 Adjustments to Fuel Cost *		0.00	0.00	0.00	0.00	0.00	0.00	$46.43
	7 TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)		41,167,609.00	40,366,954.00	36,714,090.00	31,522,245.00	27,419,421.00	28,937,434.00	$397,474,095.69
B	1 Jurisdictional KWH Sales		1,179,840,000	1,166,950,000	1,021,925,000	839,139,000	734,554,000	826,023,000	10,992,421,384
	2 Non-Jurisdictional KWH Sales		33,527,000	33,627,000	29,508,000	25,237,000	23,805,000	28,101,000	324,062,267
	3 TOTAL SALES (Lines B1 + B2)		1,213,367,000	1,200,577,000	1,051,433,000	864,376,000	758,359,000	854,124,000	11,316,483,651
	4 Jurisdictional % Of Total Sales (Line B1/B3)		97.2369%	97.1991%	97.1935%	97.0803%	96.8610%	96.7100%	
C	1 Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	(1)	43,033,176.11	42,563,029.62	37,273,425.63	30,606,536.79	26,791,930.81	30,128,147.23	$398,193,351
	2 True-Up Provision		1,614,174.00	1,614,174.00	1,614,174.00	1,614,174.00	1,614,174.00	1,614,174.00	$19,370,087
	2a Incentive Provision		(220,534.00)	(220,534.00)	(220,534.00)	(220,534.00)	(220,534.00)	(220,534.00)	($2,646,407)
	3 FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)		44,426,816.11	43,956,669.62	38,667,065.63	32,000,176.79	28,185,570.81	31,521,787.23	$414,917,030.67
	4 Fuel & Net Power Transactions (Line A7)		41,167,609.00	40,366,954.00	36,714,090.00	31,522,245.00	27,419,421.00	28,937,434.00	$397,474,096
	5 Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0015)		40,090,151.96	39,295,170.46	35,737,234.63	30,647,792.85	26,598,563.46	28,027,370.51	$386,671,923
	6 Over/(Under) Recovery (Line C3-C5)		4,336,664.15	4,661,499.16	2,929,831.00	1,352,383.94	1,587,007.35	3,494,416.72	$28,245,108
	7 Interest Provision		6,202.33	7,118.81	7,812.60	7,982.11	7,938.84	7,960.37	$80,990
	8 Adjustments (3)	(3)	0.00	0.00	0.00	0.00	0.00	(866,563.19)	($942,367)
	9 **TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2016 - DECEMBER 2016**								$27,383,731.23

* (Gain)/Loss on sales of natural gas

Notes 1: Projected Revenues based on the current approved 2016 Fuel Factor excluding revenue taxes of: 3.6474 ¢/kWh
2: Audit finding adjustment
3: January - June Scherer adjustment

SCHEDULE E-1B-1

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2016 - JUNE 2016 / ESTIMATED FOR JULY 2016 - DECEMBER 2016

	DOLLARS				kWh				¢/kWh			
	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMT.	%
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1 Fuel Cost of System Net Generation (1)	210,753,453	286,397,897	(75,644,444)	(26.41)	6,782,674,000	8,146,827,000	(1,364,153,000)	(16.74)	3.1072	3.5155	(0.4083)	(11.61)
1a Fuel Cost of Hedging Settlement	54,725,798	0	54,725,798	100.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
2 Other Generation	2,373,097	2,857,236	(484,139)	(16.94)	76,850,000	81,612,000	(4,762,000)	(5.83)	3.0880	3.5010	(0.4130)	(11.80)
3 Adjustments to Fuel Cost ***	46	0	46	100.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
4 TOTAL COST OF GENERATED POWER	267,852,395	289,255,133	(21,402,738)	(7.40)	6,859,524,000	8,228,439,000	(1,368,915,000)	(16.64)	3.9048	3.5153	0.3895	11.08
5 Energy Cost of Other Economy Purchases (Nonbroker)	177,329,071	223,394,000	(46,064,929)	(20.62)	8,807,866,927	6,944,290,000	1,863,576,927	26.84	2.0133	3.2169	(1.2036)	(37.41)
6 Energy Payments to Qualifying Facilities	5,053,715	5,291,000	(237,286)	(4.48)	190,183,000	192,036,000	(1,853,000)	(0.96)	2.6573	2.7552	(0.0979)	(3.55)
7 TOTAL COST OF PURCHASED POWER	182,382,786	228,685,000	(46,302,214)	(20.25)	8,998,049,927	7,136,326,000	1,861,723,927	26.09	2.0269	3.2045	(1.1776)	(36.75)
8 Total Available kWh (Line 4 + Line 7)	450,235,181	517,940,133	(67,704,952)	(13.07)	15,857,573,927	15,364,765,000	492,808,927	3.21	2.8392	3.3710	(0.5318)	(15.78)
9 Fuel Cost of Economy Sales	(2,357,542)	(2,673,000)	315,458	(11.80)	(113,727,971)	(113,630,000)	(97,971)	0.09	2.0730	2.3524	(0.2794)	(11.88)
10 Gain on Economy Sales	(489,951)	(564,000)	74,049	(13.13)	0	0						
11 Fuel Cost of Other Power Sales	(49,913,592)	(83,652,000)	33,738,408	(40.33)	(3,818,442,456)	(3,256,519,000)	(561,923,456)	17.26	1.3072	2.5688	(1.2616)	(49.11)
12 TOTAL FUEL COST AND GAINS ON POWER SALES	(52,761,085)	(86,889,000)	34,127,915	(39.28)	(3,932,170,427)	(3,370,149,000)	(562,021,427)	16.68	1.3418	2.5782	(1.2364)	(47.96)
13 (LINES 9+10+11)												
14 **TOTAL FUEL & NET POWER TRANSACTIONS**	397,474,096	431,051,133	(33,577,037)	(7.79)	11,925,403,500	11,994,616,000	(69,212,500)	(0.58)	3.3330	3.5937	(0.2607)	(7.25)
(LINES 8+12)												
15 Company Use *	602,943	743,501	(140,558)	(18.90)	18,090,106	20,689,000	(2,598,894)	(12.56)	3.3330	3.5937	(0.2607)	(7.25)
16 T & D Losses *	19,692,355	21,900,870	(2,208,515)	(10.08)	590,829,743	609,424,000	(18,594,257)	(3.05)	3.3330	3.5937	(0.2607)	(7.25)
17 TERRITORIAL (SYSTEM) SALES	397,474,096	431,051,133	(33,577,037)	(7.79)	11,316,483,651	11,364,503,000	(48,019,349)	(0.42)	3.5123	3.7930	(0.2807)	(7.40)
18 Wholesale Sales	11,382,189	12,536,358	(1,154,169)	(9.21)	324,062,267	330,513,000	(6,450,733)	(1.95)	3.5123	3.7930	(0.2807)	(7.40)
19 Jurisdictional Sales	386,091,907	418,514,775	(32,422,868)	(7.75)	10,992,421,384	11,033,990,000	(41,568,616)	(0.38)	3.5123	3.7930	(0.2807)	(7.40)
20 Jurisdictional Loss Multiplier	1.0015	1.0015										
21 Jurisdictional Sales Adj. for Line Losses (Line 19 x 1.0015)	386,671,923	419,142,547	(32,470,624)	(7.75)	10,992,421,384	11,033,990,000	(41,568,616)	(0.38)	3.5176	3.7986	(0.2810)	(7.40)
22 TRUE-UP **	(19,370,087)	(19,370,087)	0	0.00	10,992,421,384	11,033,990,000	(41,568,616)	(0.38)	(0.1762)	(0.1755)	(0.0007)	0.40
23 TOTAL JURISDICTIONAL FUEL COST	367,301,836	399,772,460	(32,470,624)	(8.12)	10,992,421,384	11,033,990,000	(41,568,616)	(0.38)	3.3414	3.6231	(0.2817)	(7.78)
24 Revenue Tax Factor									1.00072	1.00072		
25 Fuel Factor Adjusted for Revenue Taxes									3.3438	3.6257	(0.2819)	(7.78)
26 GPIF Reward / (Penalty) **	2,648,312	2,648,312	0	0.00	10,992,421,384	11,033,990,000	(41,568,616)	(0.38)	0.0241	0.0240	0.0001	(0.42)
27 Fuel Factor Adjusted for GPIF Reward / (Penalty)									3.3679	3.6497	(0.2818)	(7.72)
28 **FUEL FACTOR ROUNDED TO NEAREST .001(¢/kWh)**									3.368	3.650	(0.2820)	(7.73)

(1) Includes portion of Gulf's 25% ownership of Scherer Unit 3 available to the native load customers

* Included for informational purposes only.

** ¢/kWh calculation based on jurisdictional kWh sales.

*** (Gain)/Loss on sales of natural gas

Note: Amounts included in the Estimated/Actual column represent 6 months actual and 6 months estimate.

SCHEDULE E-1C

CALCULATION OF GENERATING PERFORMANCE INCENTIVE FACTOR AND TRUE-UP FACTOR
GULF POWER COMPANY
TO BE INCLUDED IN THE PERIOD: JANUARY 2017 - DECEMBER 2017

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward/(Penalty)	$	(45,708)
	B. True-up (Over)/Under Recovered	$	(26,059,665)
2.	Jurisdictional kWh sales For the period: January 2017 - December 2017		11,022,525,000
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor		(0.0004)
	B. True-up Factor		(0.2364)

SCHEDULE E-1D

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
GULF POWER COMPANY
PROPOSED FOR THE PERIOD: JANUARY 2017 - DECEMBER 2017

		NET ENERGY FOR LOAD %
	On-Peak	29.26
	Off-Peak	70.74
		100.00

	AVERAGE	ON-PEAK	OFF-PEAK
Cost per kWh Sold	3.3682	4.0049	3.1046
Jurisdictional Loss Factor	1.0015	1.0015	1.0015
Jurisdictional Fuel Factor	3.3733	4.0109	3.1093
GPIF	-0.0004	-0.0004	-0.0004
True-Up	-0.2364	-0.2364	-0.2364
TOTAL	3.1365	3.7741	2.8725
Revenue Tax Factor	1.00072	1.00072	1.00072
Recovery Factor	3.1388	3.7768	2.8746
Recovery Factor Rounded to the Nearest .001 ¢/kWh	3.139	3.777	2.875

HOURS:	ON-PEAK	25.08%
	OFF-PEAK	74.92%
		100.00%

SCHEDULE E-1E

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)
GULF POWER COMPANY
PROPOSED FOR THE PERIOD: JANUARY 2017 - DECEMBER 2017

Group	Rate Schedules	Average Factor	Fuel Recovery Loss Multipliers	Standard Fuel Recovery Factor
A	RS, RSVP, RSTOU, GS, GSD, GSDT, GSTOU, OSIII, SBS (1)	3.139	1.00773	3.163
B	LP, LPT, SBS (2)	3.139	0.98353	3.087
C	PX, PXT, RTP, SBS (3)	3.139	0.96591	3.032
D	OS-I/II	3.139	1.00777	3.125 *

		TOU
A	On-Peak	3.806
	Off-Peak	2.897
B	On-Peak	3.715
	Off-Peak	2.828
C	On-Peak	3.648
	Off-Peak	2.777
D	On-Peak	N/A
	Off-Peak	N/A

Group D Calculation

* D	On-Peak	3.777	¢ / kWh	x	0.2508	=	0.947	¢ / kWh
	Off-Peak	2.875	¢ / kWh	x	0.7492	=	2.154	¢ / kWh
							3.101	¢ / kWh
			Line Loss Multiplier			x	1.00777	
							3.125	¢ / 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

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
PROPOSED FOR THE PERIOD OF: JANUARY 2017 - DECEMBER 2017

LINE	LINE DESCRIPTION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	$													
1	Fuel Cost of System Generation [1]	20,815,766	20,698,634	21,431,188	13,109,195	19,889,549	28,017,735	35,578,402	34,308,691	26,733,009	19,231,665	18,670,987	13,578,098	272,062,919
1a	Other Generation	176,634.00	159,588.00	176,634.00	170,952.00	264,703.00	256,180.00	264,703.00	264,703.00	256,180.00	176,634.00	170,952.00	176,634.00	2,514,497
2	Fuel Cost of Power Sold	(7,346,000)	(15,198,000)	(12,643,000)	(978,000)	(5,114,000)	(7,621,000)	(15,234,000)	(15,162,000)	(10,053,000)	(7,276,000)	(5,481,000)	(3,678,000)	(105,784,000)
3	Fuel Cost of Purchased Power	17,843,000	16,370,000	18,338,000	14,337,000	18,417,000	18,544,000	19,720,000	19,420,000	19,173,000	18,332,000	11,485,000	17,665,000	209,644,000
3a	Demand & Non-Fuel Cost of Pur Power	0	0	0	0	0	0	0	0	0	0	0	0	0
3b	Qualifying Facilities	500,000	500,000	500,000	319,000	319,000	319,000	321,000	233,000	233,000	358,000	329,000	329,000	4,260,000
4	Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Hedging Settlement	0	0	0	0	0	0	0	0	0	0	0	0	0
6	**Total Fuel & Net Power Trans.** (Sum of Lines 1 - 5)	31,989,400	22,530,222	27,802,822	26,958,147	33,776,252	39,515,915	40,650,105	39,064,394	36,342,189	30,822,299	25,174,939	28,070,732	382,697,416
7	System kWh Sold	898,381,000	770,740,000	784,854,000	780,048,000	1,001,107,000	1,136,450,000	1,234,031,000	1,204,426,000	1,074,342,000	875,424,000	741,143,000	861,071,000	11,362,017,000
7a	Jurisdictional % of Total Sales	96.7730	96.8482	96.9687	96.9958	97.1550	97.2077	97.2157	97.1390	97.1778	97.0206	96.6780	96.6403	97.0120
8	Cost per kWh Sold (¢/kWh)	3.5608	2.9232	3.5424	3.4560	3.3739	3.4771	3.2941	3.2434	3.3827	3.5208	3.3968	3.2600	3.3682
8a	Jurisdictional Loss Multiplier	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015	1.0015
8b	Jurisdictional Cost (¢/kWh)	3.5661	2.9276	3.5477	3.4612	3.3790	3.4823	3.2990	3.2483	3.3878	3.5261	3.4019	3.2649	3.3733
9	GPIF (¢/kWh) *	(0.0004)	(0.0005)	(0.0005)	(0.0005)	(0.0004)	(0.0003)	(0.0003)	(0.0003)	(0.0004)	(0.0004)	(0.0005)	(0.0005)	(0.0004)
10	True-Up (¢/kWh) *	(0.2498)	(0.2909)	(0.2853)	(0.2870)	(0.2233)	(0.1966)	(0.1810)	(0.1856)	(0.2080)	(0.2557)	(0.3031)	(0.2610)	(0.2364)
11	TOTAL	3.3159	2.6362	3.2619	3.1737	3.1553	3.2854	3.1177	3.0624	3.1794	3.2700	3.0983	3.0034	3.1365
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	3.3183	2.6381	3.2642	3.1760	3.1576	3.2878	3.1199	3.0646	3.1817	3.2724	3.1005	3.0056	3.1388
14	**Recovery Factor Rounded to the Nearest .001 ¢/kWh**	3.318	2.638	3.264	3.176	3.158	3.288	3.120	3.065	3.182	3.272	3.101	3.006	3.139

* Calculations Based on Jurisdictional kWh Sales

[1] Includes portion of Gulf's 25% ownership of Scherer Unit 3 available to native load customers

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
PROPOSED FOR THE PERIOD OF: JANUARY 2017 - DECEMBER 2017

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	FUEL COST - NET GEN. ($)													
1	LIGHTER OIL (B.L.)	64,803	65,288	65,694	35,305	54,671	66,410	66,630	66,816	66,971	48,787	67,208	67,303	735,886
2	COAL	10,750,942	9,690,763	9,541,168	3,060,746	8,335,673	16,185,338	22,984,148	21,798,091	16,433,435	8,807,493	8,160,733	4,365,886	140,114,416
2a	Coal at Scherer	1,702,537	1,603,597	1,834,895	1,622,956	1,510,884	1,850,125	1,970,480	1,950,501	56,417	0	1,288,142	1,731,018	17,121,552
3	GAS - Generation	8,053,496	9,084,483	9,746,487	8,175,976	9,851,646	9,758,054	10,404,949	10,340,924	10,017,542	10,163,771	8,909,019	7,168,683	111,675,030
4	GAS (B.L.)	354,829	354,689	353,785	321,533	335,585	350,357	351,105	351,269	351,193	322,455	353,237	356,049	4,156,086
5	LANDFILL GAS	65,793	59,402	65,793	63,631	65,793	63,631	65,793	65,793	63,631	65,793	63,600	65,793	774,446
6	OIL - C.T.	0	0	0	0	0	0	0	0	0	0	0	0	0
7	TOTAL ($)	20,992,400	20,858,222	21,607,822	13,280,147	20,154,252	28,273,915	35,843,105	34,573,394	26,989,189	19,408,299	18,841,939	13,754,732	274,577,416
	SYSTEM NET GEN. (MWh)													
8	LIGHTER OIL (B.L.)	0	0	0	0	0	0	0	0	0	0	0	0	0
9	COAL	302,769	285,020	278,870	89,217	252,262	487,089	741,659	747,132	547,963	298,515	272,278	147,487	4,450,261
	Coal at Scherer	77,578	72,923	87,288	75,713	69,466	87,481	93,689	92,478	2,639	0	59,164	80,319	798,738
10	GAS	306,873	349,653	386,019	271,171	349,672	340,661	372,798	368,756	353,960	363,289	353,902	262,358	4,079,112
11	LANDFILL GAS	2,100	1,896	2,100	2,031	2,100	2,031	2,100	2,100	2,031	2,100	2,030	2,100	24,719
12	OIL - C.T.	0	0	0	0	0	0	0	0	0	0	0	0	0
13	TOTAL (MWH)	689,320	709,492	754,277	438,132	673,500	917,262	1,210,246	1,210,466	906,593	663,904	687,374	492,264	9,352,830
	UNITS OF FUEL BURNED													
14	LIGHTER OIL (BBL)	987	987	987	524	816	987	987	987	987	724	987	987	10,947
15	COAL (TON)	145,356	133,914	132,626	42,345	117,206	234,681	345,754	336,996	255,890	138,915	128,763	68,726	2,081,172
16	GAS-all (MCF) (1)	2,034,847	2,356,685	2,589,014	1,812,048	2,337,536	2,285,172	2,461,385	2,434,067	2,336,278	2,385,545	2,354,212	1,734,320	27,121,109
17	OIL - C.T. (BBL)	0	0	0	0	0	0	0	0	0	0	0	0	0
	BTUS BURNED (MMBtu)													
18	COAL + GAS B.L. + OIL B.L.	3,948,551	3,658,538	3,734,092	1,652,895	3,295,907	5,997,203	8,543,140	8,325,428	5,763,840	3,172,514	3,439,615	2,283,409	53,815,132
19	GAS-Generation (1)	2,075,544	2,403,819	2,640,794	1,848,289	2,384,287	2,330,875	2,510,613	2,482,748	2,383,004	2,433,256	2,401,296	1,769,006	27,663,531
20	OIL - C.T.	0	0	0	0	0	0	0	0	0	0	0	0	0
21	TOTAL (MMBtu) (1)	6,024,095	6,062,357	6,374,886	3,501,184	5,680,194	8,328,078	11,053,753	10,808,176	8,146,844	5,605,770	5,840,911	4,052,415	81,478,663

(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 OF: JANUARY 2017 - DECEMBER 2017

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	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	55.18	50.45	48.54	37.65	47.77	62.64	69.03	69.37	60.74	44.96	48.21	46.27	56.13
24	GAS-Generation	44.52	49.28	51.18	61.89	51.92	37.14	30.80	30.46	39.04	54.72	51.49	53.30	43.61
25	LANDFILL GAS	0.30	0.27	0.28	0.46	0.31	0.22	0.17	0.17	0.22	0.32	0.30	0.43	0.26
26	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	0.00
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 ($/BBL)	65.66	66.15	66.56	67.38	67.00	67.28	67.51	67.70	67.85	67.39	68.09	68.19	67.22
29	COAL ($/TON)	73.96	72.37	71.94	72.28	71.12	68.97	66.48	64.68	64.22	63.40	63.38	63.53	67.32
30	GAS + B.L. ($/MCF) (1)	4.05	3.94	3.83	4.60	4.24	4.31	4.26	4.28	4.33	4.32	3.86	4.24	4.18
31	OIL - C.T.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST ($ / MMBtu)													
32	COAL + GAS B.L. + OIL B.L.	3.26	3.20	3.16	3.05	3.11	3.08	2.97	2.90	2.93	2.89	2.87	2.86	2.69
33	GAS-Generation (1)	3.80	3.71	3.62	4.33	4.02	4.08	4.04	4.06	4.10	4.10	3.64	3.95	3.95
34	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	0.00
35	TOTAL ($/MMBtu) (1)	3.44	3.40	3.35	3.73	3.49	3.36	3.21	3.17	3.27	3.42	3.19	3.33	3.33
	BTU BURNED (Btu / kWh)													
36	COAL + GAS B.L. + OIL B.L.	10,381	10,221	10,198	10,022	10,244	10,438	10,227	9,916	10,468	10,628	10,378	10,023	12,093
37	GAS-Generation (1)	6,892	6,978	6,944	6,958	6,990	7,013	6,893	6,893	6,894	6,805	6,893	6,893	6,920
38	OIL - C.T.	0	0	0	0	0	0	0	0	0	0	0	0	0
39	TOTAL (Btu/kWh) (1)	8,839	8,631	8,540	8,132	8,570	9,183	9,215	9,008	9,090	8,544	8,592	8,365	8,812
	FUEL COST (Cents / kWh)													
40	COAL + GAS B.L. + OIL B.L.	3.38	3.27	3.22	3.06	3.18	3.21	3.04	2.88	3.07	3.07	2.98	2.86	3.26
41	GAS-Generation	2.62	2.60	2.52	3.02	2.82	2.86	2.79	2.80	2.83	2.80	2.52	2.73	2.74
42	LANDFILL GAS	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13	3.13
43	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	0.00
44	TOTAL (¢/kWh)	3.05	2.94	2.86	3.03	2.99	3.08	2.96	2.86	2.98	2.92	2.74	2.79	2.94

(1) Data excludes Landfill Gas and Gulf's CT in Santa Rosa County because MCF and MMBtus are not available due to contract specifications.

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROPOSED FOR THE MONTH OF: JANUARY 2017

Line	Plant/Unit	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Type	Fuel Burned (Units) (Tons/MCF/Bbl)	Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost ($)	Fuel Cost/ kWh (¢/kWh)	Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	3,676	6.6	80.6	55.7	12,001	Coal Gas - G	1,869	11,804	44,116	140,094	3.81	74.96
2	Crist 5	75	5,379	9.6	99.7	54.3	11,826	Coal Gas - G	2,695	11,804	63,614	202,011	3.76	74.96
3	Crist 6	299	71,756	32.3	98.5	62.5	11,204	Coal Gas - G	34,053	11,804	803,949	2,552,998	3.56	74.97
4	Crist 7	475	139,411	39.4	99.5	61.5	10,322	Coal Gas - G	60,952	11,804	1,438,995	4,569,633	3.28	74.97
5	Smith 3	584	301,153	69.3	83.5	86.4	6,892	Gas	2,034,847	1,020	2,075,544	7,876,862	2.62	3.87
6	Smith A (CT)	40	0	0.0	100	0.0	N/A	Oil	0	0	0	0	N/A	N/A
7	Scherer 3 (2)	162	77,578	64.4	98.5	12.4	8,749	Coal	39,933	8,498	678,716	1,702,537	2.19	42.63
8	Daniel 1 (1)	255	39,856	21.0	99.3	21.8	10,619	Coal	21,691	9,756	423,229	1,556,802	3.91	71.77
9	Daniel 2 (1)	255	42,691	22.5	92.8	22.4	11,013	Coal	24,096	9,756	470,152	1,729,404	4.05	71.77
10	Perdido		2,100					Landfill Gas				65,793	3.13	N/A
11	Other Generation		5,720					Gas				176,634	3.09	N/A
12	Gas,BL							Gas	19,608	1,020	20,000	354,829	N/A	18.10
13	Ltr. Oil							Oil	987	139,400	5,780	64,803	N/A	65.65
14		2,220	689,320	41.7	93.7	54.0	8,839				6,024,095	20,992,400	3.05	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents the portion of Gulf's 25% ownership available to native load customers

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROPOSED FOR THE MONTH OF: FEBRUARY 2017

Line	Plant/Unit	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Type	Fuel Burned (Units) (Tons/MCF/Bbl)	Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost ($)	Fuel Cost/ kWh (¢/kWh)	Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	3,141	6.0	71.4	83.8	10,129	Coal Gas - G	1,347	11,809	31,815	97,960	3.12	72.72
2	Crist 5	75	3,218	6.2	85.6	74.0	10,904	Coal Gas - G	1,486	11,809	35,090	108,044	3.36	72.71
3	Crist 6	299	68,149	32.7	98.5	61.8	10,841	Coal Gas - G	31,281	11,809	738,799	2,274,805	3.34	72.72
4	Crist 7	475	133,435	40.4	99.4	64.9	10,341	Coal Gas - G	58,424	11,809	1,379,852	4,248,644	3.18	72.72
5	Smith 3	584	344,485	84.8	99.6	88.2	6,978	Gas	2,356,685	1,020	2,403,819	8,924,895	2.59	3.79
6	Smith A (CT)	40	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
7	Scherer 3 (2)	162	72,923	64.7	98.5	13.0	8,820	Coal	37,793	8,510	643,217	1,603,597	2.20	42.43
8	Daniel 1 (1)	255	42,211	23.8	99.4	24.6	10,521	Coal	22,855	9,716	444,097	1,635,737	3.88	71.57
9	Daniel 2 (1)	255	34,866	19.6	70.8	25.3	10,322	Coal	18,521	9,716	359,888	1,325,573	3.80	71.57
10	Perdido		1,896					Landfill Gas				59,402	3.13	N/A
11	Other Generation		5,168					Gas				159,588	3.09	N/A
12	Gas,BL							Gas	19,608	1,020	20,000	354,689	N/A	18.09
13	Ltr. Oil							Oil	987	139,400	5,780	65,288	N/A	66.15
14		2,220	709,492	45.9	94.6	57.4	8,631				6,062,357	20,858,222	2.94	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents the portion of Gulf's 25% ownership available to native load customers

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROPOSED FOR THE MONTH OF: MARCH 2017

Line	Plant/Unit	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Type	Fuel Burned (Units) (Tons/MCF/Bbl)	Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost ($)	Fuel Cost/ kWh (¢/kWh)	Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	2,497	4.5	100.0	69.4	10,903	Coal Gas - G	1,153	11,811	27,225	83,188	3.33	72.15
2	Crist 5	75	4,554	8.2	83.7	57.8	11,357	Coal Gas - G	2,189	11,811	51,719	158,032	3.47	72.19
3	Crist 6	299	58,969	26.5	98.9	64.0	11,172	Coal Gas - G	27,890	11,811	658,806	2,013,038	3.41	72.18
4	Crist 7	475	141,837	40.1	86.6	67.0	10,467	Coal Gas - G	62,849	11,811	1,484,607	4,536,343	3.20	72.18
5	Smith 3	557	380,299	91.7	99.5	92.2	6,944	Gas	2,589,014	1,020	2,640,794	9,569,853	2.52	3.70
6	Smith A (CT)	36	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
7	Scherer 3 (2)	162	87,288	72.4	98.5	14.1	8,480	Coal	43,423	8,523	740,235	1,834,895	2.10	42.26
8	Daniel 1 (1)	255	56,772	29.9	99.2	22.8	10,579	Coal	31,044	9,673	600,594	2,215,274	3.90	71.36
9	Daniel 2 (1)	255	14,241	7.5	41.7	22.5	10,191	Coal	7,501	9,673	145,126	535,293	3.76	71.36
10	Perdido		2,100					Landfill Gas				65,793	3.13	N/A
11	Other Generation		5,720					Gas				176,634	3.09	N/A
12	Gas,BL							Gas	19,608	1,020	20,000	353,785	N/A	18.04
13	Ltr. Oil							Oil	987	139,400	5,780	65,694	N/A	66.56
14		2,189	754,277	46.3	89.3	57.4	8,540				6,374,886	21,607,822	2.86	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents the portion of Gulf's 25% ownership available to native load customers

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROPOSED FOR THE MONTH OF: APRIL 2017

Line	Plant/Unit	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Type	Fuel Burned (Units) (Tons/MCF/Bbl)	Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost ($)	Fuel Cost/ kWh (¢/kWh)	Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	0	0.0	100.0	0.0	N/A	Coal Gas - G	0	0	0	0	N/A	N/A
2	Crist 5	75	0	0.0	86.7	0.0	N/A	Coal Gas - G	0	0	0	0	N/A	N/A
3	Crist 6	299	14,301	6.6	19.7	60.5	12,139	Coal Gas - G	7,348	11,812	173,597	532,402	3.72	72.46
4	Crist 7	475	67,942	19.9	72.8	66.8	10,738	Coal Gas - G	30,882	11,812	729,558	2,237,469	3.29	72.45
5	Smith 3	557	265,635	66.2	69.7	94.9	6,958	Gas	1,812,048	1,020	1,848,289	8,005,024	3.01	4.42
6	Smith A (CT)	36	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
7	Scherer 3 (2)	162	75,713	64.9	98.5	13.4	8,673	Coal	38,510	8,526	656,673	1,622,956	2.14	42.14
8	Daniel 1 (1)	255	6,974	3.8	99.9	25.8	11,471	Coal	4,115	9,720	80,000	290,875	4.17	70.69
9	Daniel 2 (1)	255	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
10	Perdido		2,031					Landfill Gas				63,631	3.13	N/A
11	Other Generation		5,536					Gas				170,952	3.09	N/A
12	Gas,BL							Gas	9,804	1,020	10,000	321,533	N/A	32.80
13	Ltr. Oil							Oil	524	139,400	3,067	35,305	N/A	67.38
14		2,189	438,132	27.8	63.2	50.9	8,132				3,501,184	13,280,147	3.03	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents the portion of Gulf's 25% ownership available to native load customers

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROPOSTED FOR THE MONTH OF: MAY 2017

Line	Plant/Unit	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Type	Fuel Burned (Units) (Tons/MCF/Bbl)	Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost ($)	Fuel Cost/ kWh (¢/kWh)	Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	2,288	4.1	100.0	63.6	10,935	Coal Gas - G	1,059	11,814	25,019	75,609	3.30	71.40
2	Crist 5	75	4,594	8.2	99.9	57.8	11,620	Coal Gas - G	2,259	11,814	53,382	161,324	3.51	71.41
3	Crist 6	299	0	0.0	12.9	0.0	N/A	Coal Gas - G	0	0	0	0	N/A	N/A
4	Crist 7	475	199,258	56.4	98.4	68.4	10,447	Coal Gas - G	88,101	11,814	2,081,648	6,290,887	3.16	71.41
5	Smith 3	581	341,100	78.9	98.5	81.9	6,990	Gas	2,337,536	1,020	2,384,287	9,586,943	2.81	4.10
6	Smith A (CT)	36	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
7	Scherer 3 (2)	162	69,466	57.6	83.1	13.7	8,821	Coal	35,921	8,530	612,785	1,510,884	2.17	42.06
8	Daniel 1 (1)	255	40,923	21.6	54.3	25.5	10,922	Coal	22,901	9,759	446,962	1,605,511	3.92	70.11
9	Daniel 2 (1)	255	5,199	2.7	9.6	24.1	10,835	Coal	2,886	9,759	56,331	202,342	3.89	70.11
10	Perdido		2,100					Landfill Gas				65,793	3.13	N/A
11	Other Generation		8,572					Gas				264,703	3.09	N/A
12	Gas,BL							Gas	14,706	1,020	15,000	335,585	N/A	22.82
13	Ltr. Oil							Oil	816	139,400	4,780	54,671	N/A	67.00
14		2,213	673,500	40.9	70.6	47.0	8,570				5,680,194	20,154,252	2.99	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents the portion of Gulf's 25% ownership available to native load customers

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROPOSTED FOR THE MONTH OF: JUNE 2017

Line	Plant/Unit	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Type	Fuel Burned (Units) (Tons/MCF/Bbl)	Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost ($)	Fuel Cost/ kWh (¢/kWh)	Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	4,967	9.2	100.0	68.3	10,973	Coal Gas - G	2,314	11,777	54,503	160,071	3.22	69.18
2	Crist 5	75	13,948	25.8	99.4	65.3	11,783	Coal Gas - G	6,978	11,777	164,348	482,677	3.46	69.17
3	Crist 6	299	77,865	36.2	98.3	72.1	10,522	Coal Gas - G	34,784	11,777	819,300	2,406,220	3.09	69.18
4	Crist 7	475	228,878	66.9	98.8	76.4	10,669	Coal Gas - G	103,674	11,777	2,441,904	7,171,682	3.13	69.18
5	Smith 3	556	332,365	83.0	99.6	84.9	7,013	Gas	2,285,172	1,020	2,330,875	9,501,874	2.86	4.16
6	Smith A (CT)	32	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
7	Scherer 3 (2)	162	87,481	75.0	97.9	14.5	8,602	Coal	44,067	8,538	752,530	1,850,125	2.11	41.98
8	Daniel 1 (1)	255	83,568	45.5	99.0	28.1	10,686	Coal	44,645	10,001	893,011	3,063,271	3.67	68.61
9	Daniel 2 (1)	255	77,863	42.4	98.5	28.1	10,863	Coal	42,286	10,001	845,827	2,901,417	3.73	68.61
10	Perdido		2,031					Landfill Gas				63,631	3.13	N/A
11	Other Generation		8,296					Gas				256,180	3.09	N/A
12	Gas,BL							Gas	19,608	1,020	20,000	350,357	N/A	17.87
13	Ltr. Oil							Oil	987	139,400	5,780	66,410	N/A	67.28
14		2,184	917,262	58.3	98.9	60.3	9,183				8,328,078	28,273,915	3.08	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents the portion of Gulf's 25% ownership available to native load customers

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROPOSTED FOR THE MONTH OF: JULY 2017

Line	Plant/Unit	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Type	Fuel Burned (Units) (Tons/MCF/Bbl)	Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost ($)	Fuel Cost/ kWh (¢/kWh)	Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	35,175	63.0	100.0	71.2	10,067	Coal Gas - G	15,146	11,690	354,106	1,001,058	2.85	66.09
2	Crist 5	75	34,028	61.0	98.8	71.0	11,010	Coal Gas - G	16,024	11,690	374,643	1,059,116	3.11	66.10
3	Crist 6	299	147,541	66.3	97.3	77.7	10,386	Coal Gas - G	65,541	11,690	1,532,360	4,331,984	2.94	66.10
4	Crist 7	475	281,535	79.7	98.9	80.4	10,492	Coal Gas - G	126,340	11,690	2,953,853	8,350,547	2.97	66.10
5	Smith 3	556	364,226	88.0	99.5	88.5	6,893	Gas	2,461,385	1,020	2,510,613	10,140,246	2.78	4.12
6	Smith A (CT)	32	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
7	Scherer 3 (2)	162	93,689	77.7	98.0	15.0	8,572	Coal	46,971	8,549	803,098	1,970,480	2.10	41.95
8	Daniel 1 (1)	255	120,904	63.7	98.8	33.0	10,327	Coal	61,299	10,184	1,248,576	4,117,179	3.41	67.17
9	Daniel 2 (1)	255	122,476	64.6	98.4	32.8	10,212	Coal	61,404	10,184	1,250,724	4,124,264	3.37	67.17
10	Perdido		2,100					Landfill Gas				65,793	3.13	N/A
11	Other Generation		8,572					Gas				264,703	3.09	N/A
12	Gas,BL							Gas	19,608	1,020	20,000	351,105	N/A	17.91
13	Ltr. Oil							Oil	987	139,400	5,780	66,630	N/A	67.51
14		2,184	1,210,246	74.5	98.7	64.3	9,215				11,053,753	35,843,105	2.96	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents the portion of Gulf's 25% ownership available to native load customers

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROPOSTED FOR THE MONTH OF: AUGUST 2017

Line	Plant/Unit	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Type	Fuel Burned (Units) (Tons/MCF/Bbl)	Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost ($)	Fuel Cost/ kWh (¢/kWh)	Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	35,106	62.9	100.0	72.2	10,720	Coal Gas - G	16,159	11,645	376,335	1,037,757	2.96	64.22
2	Crist 5	75	33,172	59.4	98.8	72.3	10,966	Coal Gas - G	15,619	11,645	363,767	1,003,100	3.02	64.22
3	Crist 6	299	166,886	75.0	96.9	77.2	10,397	Coal Gas - G	74,502	11,645	1,735,114	4,784,636	2.87	64.22
4	Crist 7	475	271,117	76.7	99.1	79.2	9,414	Coal Gas - G	109,640	11,639	2,552,283	6,992,268	2.58	63.77
5	Smith 3	556	360,184	87.1	99.5	87.5	6,893	Gas	2,434,067	1,020	2,482,748	10,076,221	2.80	4.14
6	Smith A (CT)	32	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
7	Scherer 3 (2)	162	92,478	76.7	98.0	15.0	8,573	Coal	46,476	8,529	792,787	1,950,501	2.11	41.97
8	Daniel 1 (1)	255	120,931	63.7	98.8	32.3	10,339	Coal	61,057	10,239	1,250,302	4,024,350	3.33	65.91
9	Daniel 2 (1)	255	119,920	63.2	98.4	32.1	10,249	Coal	60,019	10,239	1,229,060	3,955,980	3.30	65.91
10	Perdido		2,100					Landfill Gas				65,793	3.13	N/A
11	Other Generation		8,572					Gas				264,703	3.09	N/A
12	Gas,BL							Gas	19,608	1,020	20,000	351,269	N/A	17.91
13	Ltr. Oil							Oil	987	139,400	5,780	66,816	N/A	67.70
14		2,184	1,210,466	74.5	98.7	63.7	9,008				10,808,176	34,573,394	2.86	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents the portion of Gulf's 25% ownership available to native load customers

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROPOSTED FOR THE MONTH OF: SEPTEMBER 2017

Line	Plant/Unit	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Type	Fuel Burned (Units) (Tons/MCF/Bbl)	Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost ($)	Fuel Cost/ kWh (¢/kWh)	Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	13,092	24.2	73.3	66.4	10,420	Coal Gas - G	5,860	11,639	136,421	373,741	2.85	63.78
2	Crist 5	75	13,120	24.3	72.8	65.8	11,224	Coal Gas - G	6,326	11,639	147,262	403,441	3.08	63.78
3	Crist 6	299	90,646	42.1	67.8	71.0	10,552	Coal Gas - G	41,089	11,639	956,491	2,620,415	2.89	63.77
4	Crist 7	475	246,645	72.1	98.5	76.9	10,348	Coal Gas - G	109,640	11,639	2,552,283	6,992,268	2.83	63.77
5	Smith 3	556	345,664	86.3	99.4	86.8	6,894	Gas	2,336,278	1,020	2,383,004	9,761,362	2.82	4.18
6	Smith A (CT)	32	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
7	Scherer 3 (2)	162	2,639	2.3	3.3	13.4	8,670	Coal	1,344	8,513	22,880	56,417	2.14	41.98
8	Daniel 1 (1)	255	105,606	57.5	98.8	29.5	10,394	Coal	53,079	10,340	1,097,673	3,450,245	3.27	65.00
9	Daniel 2 (1)	255	78,854	42.9	98.8	28.6	10,463	Coal	39,896	10,340	825,050	2,593,325	3.29	65.00
10	Perdido		2,031					Landfill Gas				63,631	3.13	N/A
11	Other Generation		8,296					Gas				256,180	3.09	N/A
12	Gas,BL							Gas	19,608	1,020	20,000	351,193	N/A	17.91
13	Ltr. Oil							Oil	987	139,400	5,780	66,971	N/A	67.85
14		2,184	906,593	57.7	85.8	60.9	9,090				8,146,844	26,989,189	2.98	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents the portion of Gulf's 25% ownership available to native load customers

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROPOSTED FOR THE MONTH OF: OCTOBER 2017

Line	Plant/Unit	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Type	Fuel Burned (Units) (Tons/MCF/Bbl)	Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost ($)	Fuel Cost/ kWh (¢/kWh)	Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	0	0.0	29.0	0.0	N/A	Coal Gas - G	0	0	0	0	N/A	N/A
2	Crist 5	75	0	0.0	29.0	0.0	N/A	Coal Gas - G	0	0	0	0	N/A	N/A
3	Crist 6	299	30,101	13.5	93.0	60.3	10,896	Coal Gas - G	14,125	11,609	327,970	891,757	2.96	63.13
4	Crist 7	475	213,932	60.5	99.9	0.0	10,463	Coal Gas - G	96,403	11,609	2,238,367	6,086,166	2.84	63.13
5	Smith 3	557	357,569	86.2	99.5	86.7	6,805	Gas	2,385,545	1,020	2,433,256	9,987,137	2.79	4.19
6	Smith A (CT)	36	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
7	Scherer 3 (2)	162	0	0.0	0.0	0.0	N/A	Coal	0	0	0	0	N/A	N/A
8	Daniel 1 (1)	255	19,389	10.2	73.9	24.7	11,245	Coal	10,456	10,426	218,027	673,881	3.48	64.45
9	Daniel 2 (1)	255	35,093	18.5	99.4	26.1	10,655	Coal	17,931	10,426	373,911	1,155,689	3.29	64.45
10	Perdido		2,100					Landfill Gas				65,793	3.13	N/A
11	Other Generation		5,720					Gas				176,634	3.09	N/A
12	Gas,BL							Gas	9,804	1,020	10,000	322,455	N/A	32.89
13	Ltr. Oil							Oil	724	139,400	4,239	48,787	N/A	67.39
14		2,189	663,904	40.8	83.5	36.2	8,544				5,605,770	19,408,299	2.92	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents the portion of Gulf's 25% ownership available to native load customers

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROPOSTED FOR THE MONTH OF: NOVEMBER 2017

Line	Plant/Unit	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Type	Fuel Burned (Units) (Tons/MCF/Bbl)	Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost ($)	Fuel Cost/ kWh (¢/kWh)	Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	1,991	3.7	100.0	55.3	12,041	Coal Gas - G	1,034	11,590	23,974	65,047	3.27	62.91
2	Crist 5	75	4,161	7.7	99.9	52.3	10,894	Coal Gas - G	1,956	11,590	45,332	122,995	2.96	62.88
3	Crist 6	299	29,946	13.9	98.6	56.3	11,058	Coal Gas - G	14,286	11,590	331,143	898,461	3.00	62.89
4	Crist 7	475	169,729	49.6	100.0	66.4	10,474	Coal Gas - G	76,693	11,590	1,777,736	4,823,373	2.84	62.89
5	Smith 3	557	348,366	86.8	99.4	87.3	6,893	Gas	2,354,212	1,020	2,401,296	8,738,067	2.51	3.71
6	Smith A (CT)	36	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
7	Scherer 3 (2)	162	59,164	50.7	82.2	11.8	8,802	Coal	30,668	8,490	520,778	1,288,142	2.18	42.00
8	Daniel 1 (1)	255	33,219	18.1	79.6	23.5	10,973	Coal	17,741	10,273	364,508	1,147,695	3.45	64.69
9	Daniel 2 (1)	255	33,232	18.1	99.4	22.4	10,543	Coal	17,053	10,273	350,364	1,103,162	3.32	64.69
10	Perdido		2,030					Landfill Gas				63,600	3.13	N/A
11	Other Generation		5,536					Gas				170,952	3.09	N/A
12	Gas,BL							Gas	19,608	1,020	20,000	353,237	N/A	18.01
13	Ltr. Oil							Oil	987	139,400	5,780	67,208	N/A	68.09
14		2,189	687,374	43.6	95.9	54.2	8,592				5,840,911	18,841,939	2.74	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents the portion of Gulf's 25% ownership available to native load customers

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROPOSTED FOR THE MONTH OF: DECEMBER 2017

Line	Plant/Unit	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Type	Fuel Burned (Units) (Tons/MCF/Bbl)	Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost ($)	Fuel Cost/ kWh (¢/kWh)	Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	1,991	3.6	100.0	55.3	12,041	Coal Gas - G	1,035	11,578	23,974	65,484	3.29	63.27
2	Crist 5	75	1,321	2.4	100.0	41.0	12,951	Coal Gas - G	739	11,578	17,108	46,730	3.54	63.23
3	Crist 6	299	32,574	14.6	99.3	60.9	10,874	Coal Gas - G	15,296	11,578	354,212	967,510	2.97	63.25
4	Crist 7	475	89,033	25.2	99.7	73.2	10,389	Coal Gas - G	39,943	11,578	924,963	2,526,483	2.84	63.25
5	Smith 3	584	256,638	59.1	70.6	83.7	6,893	Gas	1,734,320	1,020	1,769,006	6,992,049	2.72	4.03
6	Smith A (CT)	40	0	0.0	100.0	0.0	N/A	Oil	0	0	0	0	N/A	N/A
7	Scherer 3 (2)	162	80,319	66.6	98.5	12.9	8,707	Coal	41,207	8,485	699,306	1,731,018	2.16	42.01
8	Daniel 1 (1)	255	17,238	9.1	87.0	29.4	10,396	Coal	8,817	10,163	179,211	571,870	3.32	64.86
9	Daniel 2 (1)	255	5,330	2.8	99.9	22.1	11,042	Coal	2,896	10,163	58,855	187,809	3.52	64.85
10	Perdido		2,100					Landfill Gas				65,793	3.13	N/A
11	Other Generation		5,720					Gas				176,634	3.09	N/A
12	Gas,BL							Gas	19,608	1,020	20,000	356,049	N/A	18.16
13	Ltr. Oil							Oil	987	139,400	5,780	67,303	N/A	68.19
14		2,220	492,264	29.8	90.5	56.0	8,365				4,052,415	13,754,732	2.79	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents the portion of Gulf's 25% ownership available to native load customers

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
PROPOSTED FOR THE PERIOD OF: JANUARY 2017 - DECEMBER 2017

Line	Plant/Unit	Net Cap. (MW)	Net Gen. (MWh)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (Btu/kWh)	Fuel Type	Fuel Burned (Units) (Tons/MCF/Bbl)	Fuel Heat Value (Btu/Unit) (lbs./cf/Gal.)	Fuel Burned (MMBtu)	Fuel Burned Cost ($)	Fuel Cost/ kWh (¢/kWh)	Fuel Cost/ Unit ($/Unit)
1	Crist 4	75	103,924	15.8	87.9	69.4	10,560	Coal	46,976	11,681	1,097,488	3,100,009	2.98	65.99
								Gas - G	0	0	0	0		
2	Crist 5	75	117,495	17.8	87.9	66.3	11,203	Coal	56,271	11,696	1,316,265	3,747,470	3.19	66.60
								Gas - G	0	0	0	0		
3	Crist 6	299	788,734	30.0	81.6	69.2	10,690	Coal	360,195	11,704	8,431,741	24,274,226	3.08	67.39
								Gas - G	0	0	0	0		
4	Crist 7	475	2,182,752	52.3	96.0	71.7	10,334	Coal	963,541	11,705	22,556,049	64,825,763	2.97	67.28
								Gas - G	0.00	0.00	0.00	0.00		
5	Smith 3	566	3,997,684	80.5	93.1	87.2	6,920	Gas - G	27,121,109	1,020	27,663,531	109,160,533	2.73	4.02
6	Smith A (CT)	36	0	0.0	100.0	0.0	N/A	Oil - G	0	0	0	0	N/A	N/A
7	Scherer 3 (2)	162	798,738	56.1	93.1	87.2	8,667	Coal	406,313	8,519	6,923,005	17,121,552	2.14	42.14
8	Daniel 1 (1)	255	687,591	30.7	90.5	27.9	10,539	Coal	359,700	10,073	7,246,190	24,352,690	3.54	67.70
9	Daniel 2 (1)	255	569,765	25.4	75.7	28.2	10,470	Coal	294,489	10,128	5,965,288	19,814,258	3.48	67.28
10	Perdido		24,719					Landfill Gas				774,446	3.13	N/A
11	Other Generation		81,428					Gas				2,514,497	3.09	N/A
12	Gas,BL							Gas	210,786	1,020	215,000	4,156,086	N/A	19.72
13	Ltr. Oil							Oil	10,947	139,428	64,106	735,886	N/A	67.22
14		2,197	9,352,830	48.5	89.6	64.9	8,812				81,478,663	274,577,416	2.94	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents the portion of Gulf's 25% ownership available to native load customers

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
PROPOSED FOR THE PERIOD OF: JANUARY 2017 - DECEMBER 2017

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	LIGHT OIL													
1	*PURCHASES :*													
2	UNITS (BBL)	984	984	984	521	813	984	984	984	984	734	980	984	10,920
3	UNIT COST ($/BBL)	68.81	68.81	68.81	69.09	68.84	68.81	68.81	68.81	68.81	68.39	68.76	68.81	68.80
4	AMOUNT ($)	67,713	67,713	67,713	35,996	55,963	67,713	67,713	67,713	67,713	50,201	67,383	67,713	751,247
5	*BURNED :*													
6	UNITS (BBL)	987	987	987	524	816	987	987	987	987	724	987	987	10,947
7	UNIT COST ($/BBL)	65.66	66.15	66.56	67.38	67.00	67.28	67.51	67.70	67.85	67.39	68.09	68.19	67.22
8	AMOUNT ($)	64,803	65,288	65,694	35,305	54,671	66,410	66,630	66,816	66,971	48,787	67,208	67,303	735,886
9	*ENDING INVENTORY :*													
10	UNITS (BBL)	7,277	7,274	7,271	7,268	7,265	7,262	7,259	7,256	7,253	7,263	7,256	7,253	
11	UNIT COST ($/BBL)	66.31	66.67	66.98	67.10	67.31	67.51	67.69	67.84	67.97	68.07	68.16	68.25	
12	AMOUNT ($)	482,551	484,976	486,995	487,686	488,978	490,281	491,364	492,261	493,003	494,417	494,592	495,002	
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)	75,180	133,500	83,500	65,700	125,700	220,300	282,900	345,000	261,031	186,328	120,970	77,265	1,977,374
16	UNIT COST ($/TON)	69.56	67.59	69.41	70.28	67.60	64.28	61.93	62.55	63.07	62.11	63.27	65.49	64.31
17	AMOUNT ($)	5,229,852	9,023,728	5,795,729	4,617,174	8,497,013	14,161,103	17,518,766	21,578,879	16,464,520	11,573,135	7,653,843	5,059,939	127,173,681
18	*BURNED :*													
19	UNITS (TONS)	145,356	133,914	132,626	42,345	117,206	234,681	345,754	336,996	255,890	138,915	128,763	68,726	2,081,172
20	UNIT COST ($/TON)	73.96	72.37	71.94	72.28	71.12	68.97	66.48	64.68	64.22	63.40	63.38	63.53	67.32
21	AMOUNT ($)	10,750,942	9,690,763	9,541,168	3,060,746	8,335,673	16,185,338	22,984,148	21,798,091	16,433,435	8,807,493	8,160,733	4,365,886	140,114,416
22	*ENDING INVENTORY :*													
23	UNITS (TONS)	563,617	563,203	514,077	537,432	545,926	531,545	468,691	476,695	481,836	529,249	521,456	529,995	
24	UNIT COST ($/TON)	73.39	72.26	71.87	71.65	70.83	68.94	66.52	64.94	64.31	63.78	63.76	64.04	
25	AMOUNT ($)	41,361,541	40,694,506	36,949,067	38,505,495	38,666,835	36,642,600	31,177,218	30,958,006	30,989,091	33,754,733	33,247,843	33,941,896	
26	DAYS SUPPLY:	35	35	32	34	34	33	29	30	30	33	33	33	

(1) Data excludes Gulf's CT in Santa Rosa County because MCF and MMBtus are not available due to contract specifications.

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
PROPOSED FOR THE PERIOD OF: JANUARY 2017 - DECEMBER 2017

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	COAL at Plant Scherer													
1	*PURCHASES :*													
2	UNITS (TONS)	640,797	669,272	776,099	696,254	654,554	781,292	827,794	466,053	541,475	467,321	466,053	541,475	7,528,439
3	UNIT COST ($/TON)	2.46	2.44	2.44	2.45	2.45	2.44	2.44	2.49	2.48	2.49	2.49	2.48	2.46
4	AMOUNT ($)	1,574,475	1,636,172	1,893,659	1,705,337	1,601,443	1,905,914	2,020,616	1,160,846	1,344,895	1,163,937	1,160,846	1,344,895	18,513,035
5	*BURNED :*													
6	UNITS (TONS)	678,716	643,217	740,235	656,673	612,785	752,530	803,098	792,787	22,880	0	520,778	699,306	6,923,005
7	UNIT COST ($/TON)	2.51	2.49	2.48	2.47	2.47	2.46	2.45	2.46	2.47	0.00	2.47	2.48	2.47
8	AMOUNT ($)	1,702,537	1,603,597	1,834,895	1,622,956	1,510,884	1,850,125	1,970,480	1,950,501	56,417	0	1,288,142	1,731,018	17,121,552
9	*ENDING INVENTORY :*													
10	UNITS (TONS)	1,699,085	1,725,140	1,761,004	1,800,585	1,842,354	1,871,116	1,895,812	1,569,078	2,087,673	2,554,994	2,500,269	2,342,438	
11	UNIT COST ($/TON)	2.52	2.50	2.48	2.47	2.47	2.46	2.45	2.46	2.47	2.47	2.47	2.48	
12	AMOUNT ($)	4,278,780	4,311,355	4,370,119	4,452,500	4,543,059	4,598,848	4,648,984	3,859,329	5,147,807	6,311,744	6,184,448	5,798,325	
13	DAYS SUPPLY:	32	32	33	34	34	35	35	29	39	48	47	44	
	GAS (1)													
14	*BURNED :*													
15	UNITS (MMBtu)	2,075,544	2,403,819	2,640,794	1,848,289	2,384,287	2,330,875	2,510,613	2,482,748	2,383,004	2,433,256	2,401,296	1,769,006	27,663,531
16	UNIT COST ($/MMBtu)	3.80	3.71	3.62	4.33	4.02	4.08	4.04	4.06	4.10	4.10	3.64	3.95	3.95
17	AMOUNT ($)	7,876,862	8,924,895	9,569,853	8,005,024	9,586,943	9,501,874	10,140,246	10,076,221	9,761,362	9,987,137	8,738,067	6,992,049	109,160,533
	OTHER - C.T. OIL													
18	*PURCHASES :*													
19	UNITS (BBL)	0	0	0	0	0	0	0	0	0	0	0	0	0
20	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	AMOUNT ($)	0	0	0	0	0	0	0	0	0	0	0	0	0
22	*BURNED :*													
23	UNITS (BBL)	0	0	0	0	0	0	0	0	0	0	0	0	0
24	UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
25	AMOUNT ($)	0	0	0	0	0	0	0	0	0	0	0	0	0
26	*ENDING INVENTORY :*													
27	UNITS (BBL)	16,426	16,426	16,426	16,426	16,426	16,426	16,426	16,426	16,426	16,426	16,426	16,426	
28	UNIT COST ($/BBL)	91.53	91.53	91.53	91.53	91.53	91.53	91.53	91.53	91.53	91.53	91.53	91.53	
29	AMOUNT ($)	1,503,549	1,503,549	1,503,549	1,503,549	1,503,549	1,503,549	1,503,549	1,503,549	1,503,549	1,503,549	1,503,549	1,503,549	
30	HOURS SUPPLY:	186	186	186	186	186	186	186	186	186	186	186	186	

(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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POWER SOLD
GULF POWER COMPANY
PROPOSED FOR THE PERIOD OF: JANUARY 2017 - DECEMBER 2017

LINE	MONTH	TYPE & SCHEDULE	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	¢ / kWh FUEL COST	¢ / kWh TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST $
	JANUARY								
1		Southern Co. Interchange	322,127,000	0	322,127,000	2.17	2.56	7,000,000	8,258,000
2		Economy Sales	14,261,000	0	14,261,000	2.09	2.57	298,000	366,000
3		Gain on Economy Sales	0	0	0	0.00	0.00	48,000	48,000
4		TOTAL ESTIMATED SALES	336,388,000	0	336,388,000	2.18	2.58	7,346,000	8,672,000
	FEBRUARY								
5		Southern Co. Interchange	424,668,000	0	424,668,000	3.47	3.85	14,719,000	16,345,000
6		Economy Sales	16,476,000	0	16,476,000	2.69	3.19	443,000	525,000
7		Gain on Economy Sales	0	0	0	0.00	0.00	36,000	36,000
8		TOTAL ESTIMATED SALES	441,144,000	0	441,144,000	3.45	3.83	15,198,000	16,906,000
	MARCH								
9		Southern Co. Interchange	517,799,000	0	517,799,000	2.38	2.85	12,337,000	14,762,000
10		Economy Sales	12,216,000	0	12,216,000	2.25	2.78	275,000	339,000
11		Gain on Economy Sales	0	0	0	0.00	0.00	31,000	31,000
12		TOTAL ESTIMATED SALES	530,015,000	0	530,015,000	2.39	2.86	12,643,000	15,132,000
	APRIL								
13		Southern Co. Interchange	31,859,000	0	31,859,000	2.21	2.71	704,000	863,000
14		Economy Sales	11,195,000	0	11,195,000	2.22	2.65	249,000	297,000
15		Gain on Economy Sales	0	0	0	0.00	0.00	25,000	25,000
16		TOTAL ESTIMATED SALES	43,054,000	0	43,054,000	2.27	2.75	978,000	1,185,000
	MAY								
17		Southern Co. Interchange	210,937,000	0	210,937,000	2.27	2.71	4,787,000	5,713,000
18		Economy Sales	12,635,000	0	12,635,000	2.26	2.75	286,000	348,000
19		Gain on Economy Sales	0	0	0	0.00	0.00	41,000	41,000
20		TOTAL ESTIMATED SALES	223,572,000	0	223,572,000	2.29	2.73	5,114,000	6,102,000
	JUNE								
21		Southern Co. Interchange	300,570,000	0	300,570,000	2.46	2.98	7,399,000	8,949,000
22		Economy Sales	7,154,000	0	7,154,000	2.24	2.89	160,000	207,000
23		Gain on Economy Sales	0	0	0	0.00	0.00	62,000	62,000
24		TOTAL ESTIMATED SALES	307,724,000	0	307,724,000	2.48	3.00	7,621,000	9,218,000

POWER SOLD
GULF POWER COMPANY
PROPOSED FOR THE PERIOD OF: JANUARY 2017 - DECEMBER 2017

LINE	MONTH	TYPE & SCHEDULE	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	¢ / kWh FUEL COST	¢ / kWh TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST $
	JULY								
1		Southern Co. Interchange	551,233,000	0	551,233,000	2.70	3.25	14,895,000	17,914,000
2		Economy Sales	11,070,000	0	11,070,000	2.38	3.02	264,000	334,000
3		Gain on Economy Sales	0	0	0	0.00	0.00	75,000	75,000
4		TOTAL ESTIMATED SALES	562,303,000	0	562,303,000	2.71	3.26	15,234,000	18,323,000
	AUGUST								
5		Southern Co. Interchange	566,034,000	0	566,034,000	2.63	3.31	14,879,000	18,754,000
6		Economy Sales	9,026,000	0	9,026,000	2.28	2.98	206,000	269,000
7		Gain on Economy Sales	0	0	0	0.00	0.00	77,000	77,000
8		TOTAL ESTIMATED SALES	575,060,000	0	575,060,000	2.64	3.32	15,162,000	19,100,000
	SEPTEMBER								
9		Southern Co. Interchange	392,336,000	0	392,336,000	2.50	3.10	9,824,000	12,160,000
10		Economy Sales	7,503,000	0	7,503,000	2.35	3.04	176,000	228,000
11		Gain on Economy Sales	0	0	0	0.00	0.00	53,000	53,000
12		TOTAL ESTIMATED SALES	399,839,000	0	399,839,000	2.51	3.11	10,053,000	12,441,000
	OCTOBER								
13		Southern Co. Interchange	323,344,000	0	323,344,000	2.16	2.60	6,993,000	8,398,000
14		Economy Sales	11,913,000	0	11,913,000	2.10	2.66	250,000	317,000
15		Gain on Economy Sales	0	0	0	0.00	0.00	33,000	33,000
16		TOTAL ESTIMATED SALES	335,257,000	0	335,257,000	2.17	2.61	7,276,000	8,748,000
	NOVEMBER								
17		Southern Co. Interchange	225,415,000	0	225,415,000	2.30	2.73	5,188,000	6,151,000
18		Economy Sales	12,023,000	0	12,023,000	2.20	2.61	264,000	314,000
19		Gain on Economy Sales	0	0	0	0.00	0.00	29,000	29,000
20		TOTAL ESTIMATED SALES	237,438,000	0	237,438,000	2.31	2.74	5,481,000	6,494,000
	DECEMBER								
21		Southern Co. Interchange	152,212,000	0	152,212,000	2.23	2.65	3,389,000	4,036,000
22		Economy Sales	10,995,000	0	10,995,000	2.20	2.66	242,000	293,000
23		Gain on Economy Sales	0	0	0	0.00	0.00	47,000	47,000
24		TOTAL ESTIMATED SALES	163,207,000	0	163,207,000	2.25	2.68	3,678,000	4,376,000
	TOTAL								
25		Southern Co. Interchange	4,018,534,000	0	4,018,534,000	2.54	3.04	102,114,000	122,303,000
26		Economy Sales	136,467,000	0	136,467,000	2.28	2.81	3,113,000	3,837,000
27		Gain on Economy Sales	0	0	0	0.00	0.00	557,000	557,000
28		TOTAL ESTIMATED SALES	4,155,001,000	0	4,155,001,000	2.55	3.05	105,784,000	126,697,000

SCHEDULE E-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

PROPOSED FOR THE PERIOD OF: JANUARY 2017 - DECEMBER 2017

MONTH	PURCHASED FROM	TYPE & SCHED	TOTAL KWH PURCH.	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	¢ / kWh (A) FUEL COST	¢ / kWh (B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
January	NONE								
February	NONE								
March	NONE								
April	NONE								
May	NONE								
June	NONE								
July	NONE								
August	NONE								
September	NONE								
October	NONE								
November	NONE								
December	NONE								
Total	NONE								

SCHEDULE E-8

ENERGY PAYMENT TO QUALIFYING FACILITIES
GULF POWER COMPANY
PROPOSED FOR THE PERIOD OF: JANUARY 2017 - DECEMBER 2017

MONTH	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	¢/kWh (A) FUEL COST	¢/kWh (B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
JANUARY		COG-1	19,426,000			None	2.58	2.58	500,000
FEBRUARY		COG-1	19,426,000			None	2.58	2.58	500,000
MARCH		COG-1	19,426,000			None	2.58	2.58	500,000
APRIL		COG-1	11,378,000			None	2.80	2.80	319,000
MAY		COG-1	11,377,000			None	2.80	2.80	319,000
JUNE		COG-1	11,378,000			None	2.80	2.80	319,000
JULY		COG-1	11,477,000			None	2.80	2.80	321,000
AUGUST		COG-1	8,334,000			None	2.80	2.80	233,000
SEPTEMBER		COG-1	8,333,000			None	2.80	2.80	233,000
OCTOBER		COG-1	12,776,000			None	2.80	2.80	358,000
NOVEMBER		COG-1	12,775,000			None	2.58	2.58	329,000
DECEMBER		COG-1	12,776,000			None	2.58	2.58	329,000
TOTAL			158,882,000			0	2.68	2.68	4,260,000

SCHEDULE E-9
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ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
PROPOSED FOR THE PERIOD OF: JANUARY 2017 - DECEMBER 2017

LINE	MONTH	TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / kWh	TOTAL $ FOR FUEL ADJ.
	JANUARY				
1		Southern Co. Interchange	6,561,000	2.50	164,000
2		Economy Energy	4,079,000	2.67	109,000
3		Other Purchases	564,813,000	3.11	17,570,000
4		TOTAL ESTIMATED PURCHASES	575,453,000	3.10	17,843,000
	FEBRUARY				
5		Southern Co. Interchange	1,450,000	3.03	44,000
6		Economy Energy	4,069,000	3.12	127,000
7		Other Purchases	520,176,000	3.11	16,199,000
8		TOTAL ESTIMATED PURCHASES	525,695,000	3.11	16,370,000
	MARCH				
9		Southern Co. Interchange	23,734,000	2.65	629,000
10		Economy Energy	3,361,000	2.92	98,000
11		Other Purchases	557,391,000	3.16	17,611,000
12		TOTAL ESTIMATED PURCHASES	584,486,000	3.14	18,338,000
	APRIL				
13		Southern Co. Interchange	247,958,000	2.58	6,394,000
14		Economy Energy	5,046,000	2.70	136,000
15		Other Purchases	163,525,000	4.77	7,807,000
16		TOTAL ESTIMATED PURCHASES	416,529,000	3.44	14,337,000
	MAY				
17		Southern Co. Interchange	28,526,000	2.49	710,000
18		Economy Energy	4,735,000	2.68	127,000
19		Other Purchases	561,218,000	3.13	17,580,000
20		TOTAL ESTIMATED PURCHASES	594,479,000	3.10	18,417,000
	JUNE				
21		Southern Co. Interchange	36,305,000	3.33	1,209,000
22		Economy Energy	2,292,000	3.10	71,000
23		Other Purchases	538,890,000	3.20	17,264,000
24		TOTAL ESTIMATED PURCHASES	577,487,000	3.21	18,544,000

SCHEDULE E-9
Page 2 of 2

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
PROPOSED FOR THE PERIOD OF: JANUARY 2017 - DECEMBER 2017

LINE	MONTH	TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / kWh	TOTAL $ FOR FUEL ADJ.
	JULY				
1		Southern Co. Interchange	547,000	2.93	16,000
2		Economy Energy	4,133,000	3.34	138,000
3		Other Purchases	637,086,000	3.07	19,566,000
4		TOTAL ESTIMATED PURCHASES	641,766,000	3.07	19,720,000
	AUGUST				
5		Southern Co. Interchange	788,000	2.28	18,000
6		Economy Energy	3,856,000	3.27	126,000
7		Other Purchases	621,737,000	3.10	19,276,000
8		TOTAL ESTIMATED PURCHASES	626,381,000	3.10	19,420,000
	SEPTEMBER				
9		Southern Co. Interchange	7,392,000	2.80	207,000
10		Economy Energy	3,164,000	3.19	101,000
11		Other Purchases	607,397,000	3.11	18,865,000
12		TOTAL ESTIMATED PURCHASES	617,953,000	3.10	19,173,000
	OCTOBER				
13		Southern Co. Interchange	57,872,000	2.69	1,554,000
14		Economy Energy	5,911,000	2.57	152,000
15		Other Purchases	518,268,000	3.21	16,626,000
16		TOTAL ESTIMATED PURCHASES	582,051,000	3.15	18,332,000
	NOVEMBER				
17		Southern Co. Interchange	92,127,000	2.39	2,204,000
18		Economy Energy	5,171,000	2.53	131,000
19		Other Purchases	222,148,000	4.12	9,150,000
20		TOTAL ESTIMATED PURCHASES	319,446,000	3.60	11,485,000
	DECEMBER				
21		Southern Co. Interchange	98,699,000	2.45	2,414,000
22		Economy Energy	4,094,000	2.74	112,000
23		Other Purchases	463,881,000	3.26	15,139,000
24		TOTAL ESTIMATED PURCHASES	566,674,000	3.12	17,665,000
	TOTAL FOR PERIOD				
25		Southern Co. Interchange	601,959,000	2.59	15,563,000
26		Economy Energy	49,911,000	2.86	1,428,000
27		Other Purchases	5,976,530,000	3.22	192,653,000
28		TOTAL ESTIMATED PURCHASES	6,628,400,000	3.16	209,644,000

SCHEDULE E-10

GULF POWER COMPANY
RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1,000 kWh
PROPOSED FOR THE PERIOD OF: JANUARY 2017 - DECEMBER 2017

	Current Approved Jan. 16 - Dec. 16 ($/1,000 kWh)	Proposed Jan. 17 - Dec. 17 ($/1,000 kWh)	Difference from Current ($)	Difference from Current (%)
Base Rate	$ 64.45	$ 64.45	$ -	0.0%
Fuel Cost Recovery	36.78	31.63	(5.15)	-14.0%
Capacity Cost Recovery	9.19	8.88	(0.31)	-3.4%
Energy Conservation Cost Recovery	0.68	1.60	0.92	135.3%
Environmental Cost Recovery	21.09	21.58	0.49	2.3%
Subtotal	$ 132.19	$ 128.14	$ (4.05)	-3.1%
Gross Receipts Tax	3.39	3.29	(0.10)	-2.9%
Total	$ 135.58	$ 131.43	$ (4.15)	-3.1%

SCHEDULE E-11

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST
GULF POWER COMPANY
PROPOSED FOR THE PERIOD OF: JANUARY 2017 - DECEMBER 2017

		TOTAL ¢ / kWh
2017	JANUARY	2.576
	FEBRUARY	2.576
	MARCH	2.576
	APRIL	2.801
	MAY	2.801
	JUNE	2.801
	JULY	2.801
	AUGUST	2.801
	SEPTEMBER	2.801
	OCTOBER	2.801
	NOVEMBER	2.576
	DECEMBER	2.576
2018	JANUARY	2.627
	FEBRUARY	2.627
	MARCH	2.627
	APRIL	2.812
	MAY	2.812
	JUNE	2.812
	JULY	2.812
	AUGUST	2.812
	SEPTEMBER	2.812
	OCTOBER	2.812
	NOVEMBER	2.627
	DECEMBER	2.627

SCHEDULE H1

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
PROPOSED FOR THE PERIOD OF: JANUARY 2017 - DECEMBER 2017

LINE	LINE DESCRIPTION	2014	2015	2016	2017	% Change 2014 to 2015	% Change 2015 to 2016	% Change 2016 to 2017
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	LIGHTER OIL (B.L.)	1,745,999	1,041,770	761,818	735,886	(40.33)	(26.87)	(3.40)
2	COAL	227,098,836	137,565,166	160,639,538	140,114,416	(39.42)	16.77	(12.78)
2a	COAL at Scherer	0	0	0	17,121,552	0.00	0.00	100.00
3	GAS	124,330,289	135,200,134	120,577,791	109,160,533	8.74	(10.82)	(9.47)
4	GAS (B.L.)	1,807,910	2,330,432	3,660,486	4,156,086	28.90	57.07	13.54
5	LANDFILL GAS	680,294	963,353	758,264	774,446	41.61	(21.29)	2.13
6	OTHER - C.T.	8,702	0	0	0	(100.00)	0.00	0.00
7	OTHER GENERATION	3,254,676	2,968,865	2,857,236	2,514,497	(8.78)	(3.76)	(12.00)
8	TOTAL ($)	358,926,706	280,069,720	289,255,133	274,577,416	(21.97)	3.28	(5.07)
	SYSTEM NET GENERATION (MWh)							
9	COAL	4,980,200	3,558,501	4,597,504	4,450,261	(28.55)	29.20	(3.20)
9a	COAL at Scherer	0	0	0	798,738	0.00	0.00	100.00
10	GAS	3,846,888	3,855,439	3,524,535	3,997,684	0.22	(8.58)	13.42
11	LANDFILL GAS	24,720	31,952	24,788	24,719	29.26	(22.42)	(0.28)
12	OTHER - C.T.	32	0	0	0	(100.00)	0.00	0.00
13	OTHER GENERATION	81,428	81,428	81,612	81,428	0.00	0.23	(0.23)
14	TOTAL (MWH)	8,933,268	7,527,320	8,228,439	9,352,830	(15.74)	9.31	13.66
	UNITS OF FUEL BURNED							
15	LIGHTER OIL (BBL)	13,792	8,388	8,491	10,947	(39.18)	1.23	28.92
16	COAL excl. Scherer (TON)	2,389,900	1,752,649	2,156,455	2,081,172	(26.66)	23.04	(3.49)
17	GAS (MCF)	25,903,786	26,416,028	23,960,636	27,121,109	1.98	(9.30)	13.19
18	OTHER - C.T. (BBL)	77	0	0	0	(100.00)	0.00	0.00
	BTUS BURNED (MMBtu)							
19	COAL + GAS B.L. + OIL B.L.	55,686,060	38,051,955	48,979,775	53,815,132	(31.67)	28.72	9.87
20	GAS - Generation	26,250,901	26,416,028	24,224,848	27,663,531	0.63	(8.29)	14.19
21	OTHER - C.T.	450	0	0	0	(100.00)	0.00	0.00
22	TOTAL (MMBtu)	81,937,411	64,467,983	73,204,623	81,478,663	(21.32)	13.55	11.30
	GENERATION MIX (% MWh)							
23	COAL + GAS B.L. + OIL B.L.	55.75	47.27	55.87	56.12	(15.21)	18.19	0.45
24	GAS - Generation	43.06	51.22	42.83	42.74	18.95	(16.38)	(0.21)
25	LANDFILL GAS	0.28	0.42	0.30	0.26	50.00	(28.57)	(13.33)
26	OTHER - C.T.	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	OTHER GENERATION	0.91	1.08	0.99	0.87	18.68	(8.33)	(12.12)
28	TOTAL (% MWH)	100.00	100.00	100.00	100.00	0.00	0.00	0.00
	FUEL COST PER UNIT							
29	LIGHTER OIL B.L. ($/BBL)	126.60	124.20	89.72	67.22	(1.90)	(27.76)	(25.08)
30	COAL ($/TON)	95.02	78.49	74.49	67.32	(17.40)	(5.10)	(9.63)
31	GAS +B.L. ($/MCF)	4.87	5.21	5.19	4.18	6.98	(0.38)	(19.46)
32	OTHER - C.T.	113.01	0.00	0.00	0.00	(100.00)	0.00	0.00
	FUEL COST ($ / MMBtu)							
33	COAL + GAS B.L. + OIL B.L.	4.14	3.70	3.37	3.01	(10.63)	(8.92)	(10.68)
34	GAS - Generation	4.74	5.12	4.98	3.95	8.02	(2.73)	(20.68)
35	OTHER - C.T.	19.34	0.00	0.00	0.00	(100.00)	0.00	0.00
36	TOTAL ($/MMBtu)	4.33	4.28	3.90	3.33	(1.15)	(8.88)	(14.62)
	BTU BURNED (Btu / kWh)							
37	COAL + GAS B.L. + OIL B.L.	11,181	10,693	10,654	10,252	(4.36)	(0.36)	(3.77)
38	GAS - Generation	6,824	6,852	6,873	6,920	0.41	0.31	0.68
39	OTHER - C.T.	14,063	0	0	0	(100.00)	0.00	0.00
40	TOTAL (Btu/kWh)	9,257	8,658	9,013	8,812	(6.47)	4.10	(2.23)
	FUEL COST (¢ / kWh)							
41	COAL + GAS B.L. + OIL B.L.	4.63	3.96	3.59	2.76	(14.47)	(9.34)	(23.12)
42	GAS - Generation	3.23	3.51	3.42	2.73	8.67	(2.56)	(20.18)
43	LANDFILL GAS	2.75	3.02	3.06	3.13	9.82	1.32	2.29
44	OTHER - C.T.	27.19	0.00	0.00	0.00	(100.00)	0.00	0.00
45	OTHER GENERATION	4.00	3.65	3.50	3.09	(8.75)	(4.11)	(11.71)
46	TOTAL (¢ / kWh)	4.02	3.72	3.52	2.94	(7.46)	(5.38)	(16.48)

Schedule CCE-1

Projected Purchased Power Capacity Payments / (Receipts)
Gulf Power Company
For January 2017 - December 2017

		January	February	March	April	May	June	July	August	September	October	November	December	**Total**
1	Projected IIC Payments / (Receipts) ($)	(8,772)	0	(10,569)	34,654	0	0	0	0	0	8,370	(804)	(8,708)	14,171
2	Other Capacity Payments / (Receipts) ($)	7,170,863	7,170,863	7,170,863	7,170,863	7,170,863	7,170,863	7,170,863	7,170,863	7,170,863	7,170,863	7,170,863	7,170,863	86,050,356
3	Projected Transmission Revenue	(15,000)	(17,000)	(12,000)	(11,000)	(13,000)	(7,000)	(11,000)	(9,000)	(8,000)	(12,000)	(12,000)	(11,000)	(138,000)
4	Total Projected Capacity Payments / (Receipts) (Line 1 + 2 + 3) ($)	7,147,091	7,153,863	7,148,294	7,194,517	7,157,863	7,163,863	7,159,863	7,161,863	7,162,863	7,167,233	7,158,059	7,151,155	85,926,527
5	Jurisdictional %	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	0.9721125	
6	Projected Jurisdictional Capacity Payments / (Receipts) (Line 4 x Line 5) ($)	6,947,776	6,954,360	6,948,946	6,993,880	6,958,248	6,964,081	6,960,192	6,962,137	6,963,109	6,967,357	6,958,439	6,951,727	83,530,252
7	True-Up ($)													816,536
8	Total Jurisdictional Amount to be Recovered (Line 6 + Line 7) ($)													84,346,788
9	Revenue Tax Multiplier													1.00072
10	Total Recoverable Capacity Payments / (Receipts) (Line 8 x Line 9) ($)													84,407,518

Calculation of Jurisdictional % *

	12 CP KW	%
FPSC	1,886,812.47	97.21125%
FERC	54,127.89	2.78875%
Total	1,940,940.36	100.00000%

* Based on 2015 Actual Data

Schedule CCE-1A

PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
TO BE INCLUDED IN THE PERIOD JANUARY 2017 - DECEMBER 2017

1.	Estimated over/(under)-recovery, January 2016 - December 2016 (Schedule CCE-1B, Line 15 + Line 18)	149,231
2.	Final over/(under)-recovery, January 2015 - December 2015 (Exhibit CSB-1, Schedule CCA-1, filed March 2, 2016)	(965,767)
3.	Total over/(under)-recovery (Line 1 + 2) (To be included in January 2017 - December 2017)	($816,536)
4.	Jurisdictional kWh sales, January 2017 - December 2017	11,022,525,000
5.	True-up factor (Line 3 / Line 4) x 100 (¢/kWh)	0.0074

PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED TRUE-UP AMOUNT
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2016 - DECEMBER 2016

		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1	IIC Payments/(Receipts) ($)	(31,479)	(13,056)	(38,017)	16,919	(9,402)	(14,270)	0	0	0	0	0	0	(89,305)
2	Other Capacity Payments / (Receipts) ($)	7,386,547	7,386,547	7,386,547	7,385,880	7,435,880	7,402,529	7,198,087	7,198,087	7,198,087	7,198,087	7,198,087	7,185,442	87,559,807
3	Transmission Revenue ($)	(10,822)	(10,717)	(11,030)	(11,835)	(10,032)	(16,929)	(11,000)	(9,000)	(8,000)	(12,000)	(12,000)	(11,000)	(134,365)
4	Total Capacity Payments/(Receipts) ($)	7,344,246	7,362,774	7,337,500	7,390,964	7,416,446	7,371,330	7,187,087	7,189,087	7,190,087	7,186,087	7,186,087	7,174,442	87,336,137
5	Jurisdictional %	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	0.9707146	
6	Jurisdictional Capacity Payments/(Receipts) (Line 4 x Line 5) ($)	7,129,167	7,147,152	7,122,618	7,174,517	7,199,252	7,155,458	6,976,610	6,978,552	6,979,522	6,975,640	6,975,640	6,964,336	84,778,464
7	Retail kWh Sales							1,179,840,000	1,166,950,000	1,021,925,000	839,139,000	734,554,000	826,023,000	
8	Purchased Power Capacity Cost Recovery Factor (¢/kWh)							0.775	0.775	0.775	0.775	0.775	0.775	
9	Capacity Cost Recovery Revenues (Line 7 x Line 8/100) ($)	7,003,282	5,860,819	5,737,058	5,697,267	7,358,473	8,615,382	9,143,760	9,043,863	7,919,919	6,503,327	5,692,794	6,401,678	84,977,622
10	Revenue Taxes (Line 9 x .00072) ($)	5,042	4,220	4,131	4,102	5,298	6,203	6,584	6,512	5,702	4,682	4,099	4,609	61,184
11	True-Up Provision ($)	1,491	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488	17,859
12	Capacity Cost Recovery Revenues Net of Revenue Taxes (Line 9 - Line 10 + Line 11) ($)	6,999,731	5,858,087	5,734,415	5,694,653	7,354,663	8,610,667	9,138,664	9,038,839	7,915,705	6,500,133	5,690,183	6,398,557	84,934,297
13	Over/(Under) Recovery (Line 12 - Line 6) ($)	(129,436)	(1,289,065)	(1,388,203)	(1,479,864)	155,411	1,455,209	2,162,054	2,060,287	936,183	(475,507)	(1,285,457)	(565,779)	155,833
14	Interest Provision ($)	(337)	(590)	(1,097)	(1,463)	(1,509)	(1,344)	(811)	(143)	332	404	125	(169)	(6,602)
15	Total Estimated True-Up for the Period January 2016 - December 2016 (Line 13 + Line 14) ($)													149,231
16	Beginning Balance True-Up & Interest Provision ($)	(947,908)	(1,079,172)	(2,370,315)	(3,761,103)	(5,243,918)	(5,091,504)	(3,639,127)	(1,479,372)	579,284	1,514,311	1,037,720	(249,100)	(947,908)
17	True-Up Collected/(Refunded) ($)	(1,491)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)	(17,859)
18	Adjustment ($)	0	0	0	0	0	0	0	0	0	0	0	0	0
19	End of Period Total Net True-Up (Lines 13 + 14 + 16 + 17 + 18) ($)	(1,079,172)	(2,370,315)	(3,761,103)	(5,243,918)	(5,091,504)	(3,639,127)	(1,479,372)	579,284	1,514,311	1,037,720	(249,100)	(816,536)	(816,536)

Calculation of Purchased Power Capacity Cost Recovery Factors
Gulf Power Company
For January 2017 - December 2017

	A	B	C	D	E	F	G	H	I
Rate Class	Average 12 CP Load Factor at Meter	2017 Projected KWH Sales at Meter	Projected Avg 12 CP KW at Meter Col B / 8,760 hours x Col A	Demand Loss Expansion Factor	Energy Loss Expansion Factor	2017 Projected KWH Sales at Generation Col B x Col E	Projected Avg 12 CP KW at Generation Col C x Col D	Percentage of KWH Sales at Generation Col F / Total Col F	Percentage of 12 CP KW Demand at Generation Col G / Total Col G
RS, RSVP, RSTOU	57.542346%	5,336,892,000	1,058,758	1.00820508	1.00777864	5,378,405,762	1,067,445	48.82364%	56.78016%
GS	63.463164%	292,139,000	52,549	1.00820395	1.00777656	294,410,836	52,980	2.67258%	2.81814%
GSD, GSDT, GSTOU	73.488079%	2,650,042,000	411,653	1.00800263	1.00762887	2,670,258,826	414,948	24.23985%	22.07213%
LP, LPT	82.760718%	887,729,000	122,448	0.97344897	0.98364378	873,209,109	119,197	7.92674%	6.34039%
PX, PXT, RTP, SBS	85.375300%	1,704,488,000	227,907	0.95247952	0.96644352	1,647,291,383	217,077	14.95364%	11.54687%
OS - I / II	416.652542%	104,060,000	2,851	1.00802086	1.00777465	104,869,030	2,874	0.95197%	0.15287%
OS-III	99.799021%	47,175,000	5,396	1.00838359	1.00778595	47,542,302	5,441	0.43158%	0.28944%
TOTAL		11,022,525,000	1,881,563			11,015,987,248	1,879,962	100.00000%	100.00000%

Notes:
Col A - Average 12 CP load factor based on actual 2015 load research data.
Col C - 8,760 is the number of hours in 12 months

Calculation of Purchased Power Capacity Cost Recovery Factors
Gulf Power Company
For January 2017 - December 2017

Rate Class	A 2017 Percentage of KWH Sales at Generation Page 1, Col I	B Percentage of 12 CP KW Demand at Generation Page 1, Col J	C Energy-Related Costs ($)	D Demand-Related Costs ($)	E Total Capacity Costs ($) Col C + Col D	F 2017 Projected KWH Sales at Meter Page 1, Col B	G Capacity Cost Recovery Factors (¢ / KWH) Col E / Col F x 100	H 2017 Projected KW at Meter Page 1, Col C	I Capacity Costs Recovery Factors ($/KW) Col E / Col F x 100
RS, RSVP, RSTOU	48.82364%	56.78016%	3,170,063	44,240,053	47,410,116	5,336,892,000	0.888		
GS	2.67258%	2.81814%	173,528	2,195,743	2,369,271	292,139,000	0.811		
GSD, GSDT, GSTOU	24.23985%	22.07213%	1,573,866	17,197,419	18,771,285	2,650,042,000	0.708		
LP, LPT	7.92674%	6.34039%	514,674	4,940,092	5,454,766	887,729,000	0.000	1,833,899	2.97
PX, PXT, RTP, SBS	14.95364%	11.54687%	970,923	8,996,701	9,967,624	1,704,488,000	0.585		
OS - I / II	0.95197%	0.15287%	61,810	119,108	180,918	104,060,000	0.174		
OS-III	0.43158%	0.28944%	28,022	225,516	253,538	47,175,000	0.537		
TOTAL	100.00000%	100.00000%	$6,492,886	$77,914,632	$84,407,518	11,022,525,000	0.766	1,833,899	2.97

Notes:
Col C - (Recoverable Amount from Schedule CCE-1, line 10) / 13 x Col A
Col D - (Recoverable Amount from Schedule CCE-1, line 10) x 12 / 13 x Col B

Gulf Power Company
2017 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** [2]	**11/2/2009**	**5/31/2023**		**Firm**									
5 ***Other***													
6 **South Carolina PSA**	**9/1/2003**	**-**		**Other**									
7 **Souther Caroline Electric & Gas**	**1/1/2017**	**-**		**Other**									

8 **Capacity Costs ($)**		January	February	March	April	May	June	July	August	September	October	November	December	Total
9 Southern Intercompany Interchange		(8,772)	0	(10,569)	34,654	0	0	0	0	0	8,370	(804)	(8,708)	14,171
10 *PPAs*														
11 Shell Energy N.A. (U.S.), LP		[redacted]												
12 *Other*														
13 South Carolina PSA		[redacted]												
14 South Caroline Electric & Gas														
15	Total	7,162,091	7,170,863	7,160,294	7,205,517	7,170,863	7,170,863	7,170,863	7,170,863	7,170,863	7,179,233	7,170,059	7,162,155	86,064,527

16 **Capacity MW**	January	February	March	April	May	June	July	August	September	October	November	December
17 Southern Intercompany Interchange	(10.7)	0 0	(32.4)	212 3	0.0	0.0	0 0	0.0	0.0	51.2	(4 9)	53.3
18 *PPAs*												
19 Shell Energy N.A. (U.S.), LP	[redacted]											
20 *Other*												
21 South Carolina PSA	[redacted]											
22 South Caroline Electric & Gas												

23 (1) Unless otherwise noted, contract remains effective unless terminated upon 30 days prior written notice.
24 (2) Contract megawatts became firm on June 1, 2014.

EXHIBIT TO THE TESTIMONY OF

C. L. NICHOLSON

IN FPSC DOCKET 160001-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 47
PARTY: GULF POWER COMPANY – (DIRECT)
DESCRIPTION: C. L. Nicholson CLN-1

I. CORRECTIONS TO REPORTED DATA FOR THE JANUARY 2015 - DECEMBER 2015 PERIOD

Additions and Corrections to Outages Previously Reported
for the January 2015 - December 2015 Period

Date	Unit	Change	Outage Type	Hours	MW	Description
July filing	Smith 3	Revised capacity reduction	PMO	36.7	239.0	Capacity reduction entered was incorrect. EAF changed from 98.1% to 97.9%.
August filing	Daniel 1	FMO - PO		108.7	510.0	No change to EAF 108.7 MOH changed to POH.
August filing	Crist 6	Deleted time	FMO	51.9	299.0	Corrected end date error. EAF changed from 84.0% to 93.0%.
		Add event	RSH	67.1	299.0	Added RSH after correcting FMO input error.

II. CALCULATIONS OF EQUIVALENT AVAILABILITY POINTS

Comparison of Forecast and Actual Planned Outages
for January 2015 - December 2015

Unit	Note	Forecast Planned Outage Schedule	Forecast Hours*	Actual Planned Outage Schedule	Actual Hours*
Daniel 1	1	01/17/15 - 03/29/15	1704.0	01/17/15 - 04/07/15	1937.9
Daniel 1	2	N/A	N/A	04/07/15 - 04/07/15	0.3
Daniel 1	2	N/A	N/A	04/08/15 - 04/09/15	16.4
Daniel 1	2	N/A	N/A	08/12/15 - 08/17/15	108.7
Daniel 2		01/19/15 - 01/27/15	216.0	01/19/15 - 01/28/15	216.0
Daniel 2		03/16/15 - 03/24/15	216.0	03/16/15 - 03/25/15	216.0
Daniel 2	2	N/A	N/A	04/07/15 - 04/07/15	1.4
Daniel 2	2	N/A	N/A	09/08/15 - 09/12/15	89.9

* Planned outage hours in the January 2015 - December 2015 period only.

Notes: 1. This outage was extended due to induced draft fan blade work.

2. The outage was added subsequent to the target filing.

3. This outage proceeded as scheduled and was completed ahead of schedule.

4. The outage date was changed subsequent to the target filing.

Comparison of Forecast and Actual Planned Outages
for January 2015 - December 2015

Unit	Note	Forecast Planned Outage Schedule	Forecast Hours*	Actual Planned Outage Schedule	Actual Hours*
Crist 6	3	3/28/15 - 5/31/15	1560.0	3/28/15 - 5/27/15	1442.8
Crist 7	4	05/09/15 - 05/15/15	168.0	4/4/15 - 4/13/15	207.2
Crist 7	2	N/A	N/A	10/18/15 - 11/05/15	443.8
Smith 3	4	04/25/15 - 05/03/15	216.0	03/18/15 - 03/28/15	219.6
Smith 3	4	11/21/15 - 11/29/15	216.0	11/06/15 - 11/19/15	291.9

* Planned outage hours in the January 2015 - December 2015 period only.

Notes:
1. This outage was extended due to induced draft fan blade work.
2. The outage was added subsequent to the target filing.
3. This outage proceeded as scheduled and was completed ahead of schedule.
4. The outage date was changed subsequent to the target filing.

Calculation of Actual Equivalent Availability
for January 2015 - December 2015
Based on Target Planned Outage Hours
Crist 6

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.9	0.0	0.0	0.0	0.0	3.4	
	0.0	0.0	2.5	0.0	0.0	0.0	6.8
EFOH	0.0	66.9	0.0	0.0	0.0	1.1	
	0.2	0.0	0.0	0.0	0.0	0.0	68.2
MOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	51.9	0.0	96.6	0.0	0.0	148.5
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PH	744.0	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	96.0	720.0	626.8	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	1442.8
RSH	581.3	266.0	486.8	0.0	0.0	255.5	
	238.5	520.2	219.8	480.2	721.0	744.0	4513.3

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(6.8 + 68.2 + 148.5 + 0.0)}{(8760.0 - 1442.8 - 4513.3)}$$

EUOR = 0.0797

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 1560.0

Target RSH* = 6247.5

$$EA = \left[1 - \frac{(1560.0 + 0.0797\ (8760.0 - 1560.0 - 6247.5))}{8760.0} \right] \times 100 = 81.3\ \%$$

Note: Please refer to page 10 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2015 - December 2015
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	1.9	0.0	0.0	0.0	0.0	3.5	
	0.0	0.0	0.0	0.0	2.2	0.0	7.6
EFOH	19.3	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	19.3
MOH	0.0	67.7	0.0	173.5	0.0	0.0	
	0.0	81.4	0.0	0.0	0.0	0.0	322.6
EMOH	3.3	0.0	0.0	4.4	0.0	5.7	
	13.3	0.0	0.0	0.0	0.0	0.0	26.7
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	0.0	207.2	0.0	0.0	
	0.0	0.0	0.0	336.0	107.8	0.0	651.0
RSH	44.3	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	20.3	440.4	744.0	1249.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(7.6 + 19.3 + 322.6 + 26.7)}{(8760.0 - 651.0 - 1249.0)}$$

$$EUOR = 0.0548$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 168.0

Target RSH* = 4289.8

$$EA = \left[1 - \frac{(168.0 + 0.0548\ (8760.0 - 168.0 - 4289.8))}{8760.0} \right] \times 100 = 95.4\ \%$$

Note: Please refer to page 10 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2015 - December 2015
Based on Target Planned Outage Hours
Daniel 1

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	5.0	1.3	5.3	
	0.0	0.0	0.0	0.0	0.0	0.0	11.6
EFOH	0.6	0.0	0.0	0.5	3.5	4.6	
	0.0	1.2	0.0	0.0	0.3	0.0	10.7
MOH	0.0	0.0	0.0	0.0	0.0	51.1	
	0.0	0.0	0.0	0.0	0.0	0.0	51.1
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PH	744.0	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	360.0	672.0	743.0	179.5	0.0	0.0	
	0.0	108.7	0.0	0.0	0.0	0.0	2063.2
RSH	272.8	0.0	0.0	141.6	0.0	0.0	
	0.0	0.0	481.7	744.0	402.8	744.0	2786.9

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(11.6 + 10.7 + 51.1 + 0.0)}{(8760.0 - 2063.2 - 2786.9)}$$

$$EUOR = 0.0188$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

$$Target\ POH^* = 1704.0$$

$$Target\ RSH^* = 1581.7$$

$$EA = \left[1 - \frac{(1704.0 + 0.0188\ (8760.0 - 1704.0 - 1581.7))}{8760.0} \right] \times 100 = 79.4\ \%$$

Note: Please refer to page 10 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2015 - December 2015
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	10.4	0.0	5.9	1.7	2.5	
	3.3	0.0	0.0	0.0	0.0	4.0	27.8
EFOH	0.0	2.6	0.0	1.4	5.1	0.0	
	0.1	0.0	0.4	0.0	0.0	0.0	9.6
MOH	0.0	0.0	0.0	0.0	0.0	9.7	
	3.2	0.0	0.0	0.0	0.0	0.0	12.9
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PH	744.0	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	216.0	0.0	216.0	1.4	0.0	0.0	
	0.0	0.0	89.9	0.0	0.0	0.0	523.3
RSH	383.0	276.1	367.8	328.5	123.1	0.0	
	0.0	0.0	159.7	529.4	606.6	606.9	3381.1

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(27.8 + 9.6 + 12.9 + 0.0)}{(8760.0 - 523.3 - 3381.1)}$$

$$EUOR = 0.0104$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 432.0

Target RSH* = 1238.5

$$EA = \left[1 - \frac{(432.0 + 0.0104\ (8760.0 - 432.0 - 1238.5))}{8760.0} \right] \times 100 = 94.2\ \%$$

Note: Please refer to page 10 of this Schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2015 - December 2015
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	0.0	0.0	5.6	5.6
EFOH	0.0	2.2	0.0	3.3	0.0	0.0	
	0.0	0.0	2.5	0.0	5.3	0.0	13.3
MOH	0.0	4.6	0.0	0.0	43.1	68.6	
	0.0	0.0	0.0	0.0	0.0	0.0	116.3
EMOH	2.8	0.0	0.0	0.0	0.0	0.0	
	15.8	0.0	0.0	0.0	2.8	8.4	29.8
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	219.6	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	291.9	0.0	511.5
RSH	0.0	8.6	0.0	34.0	52.3	41.3	
	0.0	7.8	47.6	0.0	74.2	74.1	339.9

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(5.6 + 13.3 + 116.3 + 29.8)}{(8760.0 - 511.5 - 339.9)}$$

$$EUOR = 0.0209$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 432.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(432.0 + 0.0209\ (8760.0 - 432.0 - 0.0))}{8760.0} \right] \times 100 = 93.1\ \%$$

Note: Please refer to page 10 of this Schedule for an explanation of symbols.

Calculation of Equivalent Availability Points
for January 2015 - December 2015

(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***
Crist 6	81.1	81.3	81.6	4.00
Crist 7	94.9	95.4	96.0	4.55
Daniel 1	73.3	79.4	75.0	10.00
Daniel 2	88.7	94.2	89.9	10.00
Smith 3	92.7	93.1	93.4	5.71

* As appropriate from page 5, Schedule 3 of Exhibit to M. A. Young, III's August 22, 2014 GPIF Testimony in Docket 140001-EI.

** Refer to pages 4 through 8 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 2015 - December 2015

Crist 6

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	26908.5	58075.2	23845.2	0.0	17280.8	80635.3	
	92849.3	27673.4	81783.4	27449.5	0.0	0.0	436500.6
BTU/Lb*	11819.3	11402.3	11658.8	0.0	11291.0	11574.3	
	11498.6	11630.1	11664.0	11593.9	0.0	0.0	11565.4
Coal, MMBTU	318038.8	662191.4	278005.9	0.0	195117.0	933296.3	
	1067637.9	321845.5	953924.8	318245.9	0.0	0.0	5048303.5
Oil, MMBTU	5.7	427.9	0.0	0.0	0.0	4711.8	
	1.0	0.0	23.5	0.0	0.0	0.0	5169.9
Gas, MMBTU	16024.3	93705.6	80283.9	0.0	24990.0	8269.1	
	2215.2	8802.5	2468.9	2.0	0.0	0.0	236761.5
Startup, MMBTU **	-4040.0	-4040.0	0.0	0.0	-4040.0	-4040.0	
	-4040.0	-4040.0	-4040.0	0.0	0.0	0.0	-28280.0
Total Fuel Consumption, MMBTU	330028.8	752284.9	358289.8	0.0	216067.0	942237.2	
	1065814.1	326608.0	952377.2	318247.9	0.0	0.0	5261954.9
Net MWH Generation***	28493	70529	30838	0	17788	87284	
	97019	29956	83095	28381	0	0	473383
Average Net Operating Heat Rate	11583	10666	11618	---	12147	10795	
	10986	10903	11461	11213	---	---	11116

* 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 2015 - December 2015

Crist 7

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	158607.0	144713.1	176021.8	76721.8	197989.6	202512.1	
	229902.1	186509.1	175956.5	89726.5	39054.0	0.0	1677713.6
BTU/Lb*	11525.4	11494.7	11533.7	11405.5	11466.3	11581.9	
	11514.9	11556.8	11629.4	11730.2	11090.5	0.0	11531.8
Coal, MMBTU	1828004.4	1663438.0	2030186.2	875052.8	2270212.1	2345481.0	
	2647290.5	2155452.1	2046261.5	1052507.1	433127.2	0.0	19347012.9
Oil, MMBTU	156.0	816.5	20.1	320.6	170.8	297.6	
	27.8	606.5	214.3	42.0	1545.2	0.0	4217.4
Gas, MMBTU	24307.0	28609.4	2199.1	17858.4	0.0	0.0	
	16.1	2621.0	1156.1	0.1	6993.7	0.0	83760.9
Startup, MMBTU **	-2256.0	-2256.0	0.0	-4512.0	0.0	0.0	
	0.0	-2256.0	0.0	0.0	-2256.0	0.0	-13536.0
Total Fuel Consumption, MMBTU	1850211.4	1690607.9	2032405.4	888719.8	2270382.9	2345778.6	
	2647334.4	2156423.6	2047631.9	1052549.2	439410.1	0.0	19421455.2
Net MWH Generation***	179147	160821	187050	80425	217393	218145	
	245198	202372	193205	96246	40396	0	1820398
Average Net Operating	10328	10512	10866	11050	10444	10753	
	10797	10656	10598	10936	10878	---	10669

* 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 2015 - December 2015

Daniel 1

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	22114.0	0.0	0.0	118790.0	213226.0	180192.0	
	230604.0	202490.0	67958.0	0.0	74790.0	0.0	1110164.0
BTU/Lb*	10948.8	0.0	0.0	9921.7	11111.1	10872.9	
	10377.4	9663.6	9394.9	0.0	9158.5	0.0	10288.9
Coal, MMBTU	242121.3	0.0	0.0	1178595.2	2369181.8	1959206.0	
	2393065.3	1956774.3	638457.9	0.0	684961.2	0.0	11422363.0
Oil, MMBTU	0.0	0.0	0.0	27263.3	18591.1	9289.6	
	1.3	3809.9	238.6	0.0	4495.9	0.0	63689.7
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	0.0	-4777.4	0.0	-2388.7	
	0.0	-2388.7	0.0	0.0	-2388.7	0.0	-14332.2
Total Fuel Consumption, MMBTU	239732.6	0.0	0.0	1201081.1	2387772.9	1966106.9	
	2393066.6	1958195.5	638696.5	0.0	687068.4	0.0	11471720.5
Net MWH Generation***	23099	0	0	100571	212167	183189	
	235565	186808	64999	0	59205	0	1065603
Average Net Operating	10378	---	---	11943	11254	10733	
	10159	10482	9826	---	11605	---	10765

* 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 2015 - December 2015

Daniel 2

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	36700.0	83112.0	33468.0	98070.0	186496.0	207002.0	
	238558.0	287122.0	162290.0	46752.0	24052.0	41084.0	1444706.0
BTU/Lb*	10997.1	10757.9	9033.0	10242.5	11070.7	11243.8	
	10659.7	10328.4	9820.7	9575.9	8498.2	10879.8	10519.8
Coal, MMBTU	403592.8	894108.1	302317.1	1004480.0	2064635.7	2327491.2	
	2542966.3	2965510.9	1593804.6	447693.9	204398.2	446983.6	15197982.4
Oil, MMBTU	0.0	13579.6	518.2	8530.0	8487.5	3524.7	
	2162.7	15.0	2800.7	112.1	3288.4	4228.5	47247.4
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 **	-4777.4	-2388.7	0.0	-2388.7	-2388.7	0.0	
	0.0	0.0	-2388.7	0.0	-2388.7	-2388.7	-19109.6
Total Fuel Consumption, MMBTU	398815.4	905299.0	302835.3	1010621.3	2070734.5	2331015.9	
	2545129.0	2965525.9	1594216.6	447806.0	205297.9	448823.4	15226120.2
Net MWH Generation***	31796	82140	29549	95157	175060	200812	
	245916	292620	153673	44201	18442	37173	1406539
Average Net Operating	12543	11021	10249	10621	11829	11608	
	10350	10134	10374	10131	11132	12074	10825

* 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 2015 - December 2015

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	2474151.0	2210303.0	1546370.3	2140768.0	2119315.0	1986146.0	
	2331163.0	2355662.0	2170720.0	2512797.0	1150181.6	2126033.0	25123609.9
Startup, 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
Total Fuel Consumption, MMBTU	2474151.0	2210303.0	1546370.3	2140768.0	2119315.0	1986146.0	
	2331163.0	2355662.0	2170720.0	2512797.0	1150181.6	2126033.0	25123609.9
Net MWH Generation***	359330	321535	221511	311321	306763	286484	
	335751	340084	313758	370708	166496	306985	3640726
Average Net Operating	6885	6874	6981	6876	6909	6933	
	6943	6927	6918	6778	6908	6926	6901

* 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 2015 - December 2015
Adjusted to Target Basis Using Heat Rate
Equations Filed August 22, 2014

Crist 6

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	12828	13575	13201	0	0	0	
		12029	0	0	0	0	12029	
2.	Target Heat Rate	11534	11779	11488	0	11463	10784	
	at Actual Conditions**	10732	11339	11061	11218	0	12029	
3.	Adjustment to Actual	1294	1796	1713	0	1070	1749	
	Heat Rate (1-2)	1297	1194	1472	1315	0	0	
4.	Actual Heat Rate	11583	10666	11618	0	12147	10794	
	(Page 2 of Sched. 3)	10986	10903	11461	11213	0	0	
5.	Adjusted Actual	12877	12462	13331	0	13217	12543	
	Heat Rate (4+3)	12283	12097	12933	12528	0	0	
6.	Net MWH Generation	28493	70529	30838	0	17788	87284	
		97019	29956	83095	28381	0	0	
7.	Adjusted Actual Heat Rate for January 2015 - December 2015 =(Σ (5*6) / Σ 6)							12614

* From pages 17 & 18, Schedule 3 of Exhibit to M. A. Young, III's August 22, 2014 GPIF Testimony in Docket 140001-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 2015 - December 2015
Adjusted to Target Basis Using Heat Rate
Equations Filed August 22, 2014

Crist 7

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10947	10951	10680	11274	0	10821	
		10723	10739	10864	0	0	10896	
2.	Target Heat Rate	11000	10955	10723	11499	10834	10804	
	at Actual Conditions**	10737	10812	10936	11046	11255	10896	
3.	Adjustment to Actual	-53	-4	-43	-225	56	17	
	Heat Rate (1-2)	-14	-73	-72	-156	-365	0	
4.	Actual Heat Rate	10328	10512	10866	11050	10444	10753	
	(Page 3 of Sched. 3)	10797	10656	10598	10936	10877	0	
5.	Adjusted Actual	10275	10508	10823	10825	10500	10770	
	Heat Rate (4+3)	10783	10583	10526	10780	10512	0	
6.	Net MWH Generation	179147	160821	187050	80425	217393	218145	
		245198	202372	193205	96246	40396	0	
7.	Adjusted Actual Heat Rate for January 2015 - December 2015 =(Σ (5*6) / Σ 6)							10624

* From pages 19 & 20, Schedule 3 of Exhibit to M. A. Young, III's August 22, 2014 GPIF Testimony in Docket 140001-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 2015 - December 2015
Adjusted to Target Basis Using Heat Rate
Equations Filed August 22, 2014

Daniel 1

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10150	0	0	10316	10595	10282	
		10230	10224	10293	10911	10749	10684	
2.	Target Heat Rate	10907	0	0	10603	10739	10503	
	at Actual Conditions**	10347	10429	10518	10911	11576	10684	
3.	Adjustment to Actual	-757	0	0	-287	-144	-221	
	Heat Rate (1-2)	-117	-205	-225	0	-827	0	
4.	Actual Heat Rate	10379	0	0	11938	11253	10732	
	(Page 4 of Sched. 3)	10159	10482	9826	0	11604	0	
5.	Adjusted Actual	9622	0	0	11651	11109	10511	
	Heat Rate (4+3)	10042	10277	9601	0	10777	0	
6.	Net MWH Generation	23099	0	0	100571	212167	183189	
		235565	186808	64999	0	59205	0	
7.	Adjusted Actual Heat Rate for January 2015 - December 2015 =(Σ (5*6) / Σ 6)							10533

* From pages 21 & 22 , Schedule 3 of Exhibit to M. A. Young, III's August 22, 2014 GPIF Testimony in Docket 140001-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 2015 - December 2015
Adjusted to Target Basis Using Heat Rate
Equations Filed August 22, 2014

Daniel 2

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10822	9400	10268	10222	10273	10177	
		10135	10129	10190	10917	10398	10843	
2.	Target Heat Rate	10470	9669	11624	10676	10461	10456	
	at Actual Conditions**	10229	10033	10256	11783	11609	10480	
3.	Adjustment to Actual	352	-269	-1356	-454	-188	-279	
	Heat Rate (1-2)	-94	96	-66	-866	-1211	363	
4.	Actual Heat Rate	12543	11020	10248	10619	11828	11608	
	(Page 5 of Sched. 3)	10350	10134	10374	10131	11130	12073	
5.	Adjusted Actual	12895	10751	8892	10165	11640	11329	
	Heat Rate (4+3)	10256	10230	10308	9265	9919	12436	
6.	Net MWH Generation	31796	82140	29549	95157	175060	200812	
		245916	292620	153673	44201	18442	37173	
7.	Adjusted Actual Heat Rate for January 2015 - December 2015 =(Σ (5*6) / Σ 6)							10658

* From pages 23 & 24, Schedule 3 of Exhibit to M. A. Young, III's August 22, 2014 GPIF Testimony in Docket 140001-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 2015 - December 2015
Adjusted to Target Basis Using Heat Rate
Equations Filed August 22, 2014

Smith 3

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	6886	6869	6874	6858	6864	6874	
		6838	6841	6871	6790	6838	6828	
2.	Target Heat Rate	6846	6840	6938	6888	6860	6865	
	at Actual Conditions**	6892	6876	6869	6758	6866	6876	
3.	Adjustment to Actual	40	29	-64	-30	4	9	
	Heat Rate (1-2)	-54	-35	2	32	-28	-48	
4.	Actual Heat Rate***	6885	6874	6981	6876	6909	6933	
	(Page 6 of Sched. 3)	6943	6927	6918	6778	6908	6926	
5.	Adjusted Actual	6925	6903	6917	6846	6913	6942	
	Heat Rate (4+3)	6889	6892	6920	6810	6880	6878	
6.	Net MWH Generation	359330	321535	221511	311321	306763	286484	
		335751	340084	313758	370708	166496	306985	
7.	Adjusted Actual Heat Rate for January 2015 - December 2015 =(Σ (5*6) / Σ 6)							6892

* From pages 25 & 26, Schedule 3 of Exhibit to M. A. Young, III's August 22, 2014 GPIF Testimony in Docket 140001-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 2015 - December 2015

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec
Crist 6							
	+3						
	AKW * 10	176.1	173.7	192.5	0.0	151.8	189.3
		191.9	174.2	167.0	169.7	0.0	0.0
	+6						
	LSRF * 10	33583.0	31260.4	37612.2	0.0	28909.4	37696.8
		37624.5	32434.1	28888.8	29194.1	0.0	0.0
Crist 7							
	+3						
	AKW * 10	256.7	266.1	251.7	237.0	292.2	304.5
		329.6	305.4	268.3	248.2	236.8	0.0
	+6						
	LSRF * 10	67865.1	74129.7	64028.8	58594.6	90772.2	100149.8
		118171.3	101567.7	75016.5	62313.0	63439.1	0.0
Daniel 1							
	+3						
	AKW * 10	207.7	0.0	0.0	255.3	285.7	276.1
		316.6	294.0	272.8	0.0	186.1	0.0
	+6						
	LSRF * 10	49252.0	0.0	0.0	74261.4	92292.9	87431.8
		117999.9	104214.7	93316.8	0.0	42370.3	0.0
Daniel 2							
	+3						
	AKW * 10	219.3	213.1	185.6	247.7	282.7	283.7
		333.4	393.3	326.7	206.0	161.2	279.3
	+6						
	LSRF * 10	56611.5	49355.5	34882.4	68192.7	92146.5	93248.9
		128623.5	157942.4	119333.7	46238.3	29674.1	100055.6
Smith 3							
	+3						
	AKW * 10	483.0	488.1	423.2	453.8	473.0	469.6
		451.3	461.9	466.6	498.3	469.1	462.1
	+6						
	LSRF * 10	241939.7	252086.1	194114.0	214785.5	233335.0	230228.8
		214992.5	222569.9	230211.7	254331.9	231423.4	223744.8

Target Heat Rate Equations

Crist 6 ANOHR = 10^6 / AKW * [547.85 + 100.05 * JAN + 141.57 * FEB + 147.80 * MAR + 131.25 * APR + 62.34 * AUG + 36.24 * OCT]
+ 7,054 + 0.00420 * LSRF / AKW

Crist 7 ANOHR = 10^6 / AKW * [735.33 - 74.26 * MAR + 77.66 * APR]
+ 7,097 + 0.00393 * LSRF / AKW

Daniel 1 ANOHR = 10^6 / AKW * [338.36 + 79.10 * MAY + 137.43 * OCT + 89.35 * NOV]
+ 9,278

Daniel 2 ANOHR = 10^6 / AKW * [430.73 - 94.68 * JAN - 274.79 * FEB + 67.80 * MAR + 155.49 * OCT]
+ 8,937

Smith 3 ANOHR = 10^6 / AKW * [314.69 - 33.91 * OCT]
+ 6,195

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 2015 - December 2015

(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***
Crist 6	12533	12614	12157	-0.20
Crist 7	10890	10624	10563	7.58
Daniel 1	10366	10533	10055	-3.90
Daniel 2	10196	10658	9890	-10.00
Smith 3	6852	6892	6646	0.00

* From page 5, Schedule 3 of Exhibit to M. A. Young, III's August 22, 2014 GPIF Testimony in Docket 140001-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 2015 - December 2015

Unit	Availability Points	Availability* Weighting Factor	Heat Rate Points	Heat Rate* Weighting Factor
Crist 6	4.00	0.000	-0.20	0.021
Crist 7	4.55	0.000	7.58	0.182
Daniel 1	10.00	0.006	-3.90	0.101
Daniel 2	10.00	0.005	-10.00	0.135
Smith 3	5.71	0.019	0.00	0.530

Company GPIF Points =

+ 4.00 * 0.000 - 0.20 * 0.021

+ 4.55 * 0.000 + 7.58 * 0.182

+ 10.00 * 0.006 - 3.90 * 0.101

+ 10.00 * 0.005 - 10.00 * 0.135

+ 5.71 * 0.019 + 0.00 * 0.530

= -0.13

Company reward/penalty = -0.13 points * $351600 per point

= ($45,708)

* From page 5, Schedule 3 of Exhibit to M. A. Young, III's August 22, 2014 GPIF Testimony in Docket 140001-EI.

V. GPIF MINIMUM FILING REQUIREMENTS FOR THE JANUARY 2015 - DECEMBER 2015 PERIOD

CONTENTS

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Generating Performance Incentive Factor

Actual Reward/Penalty Table

Gulf Power Company

Period of: January 2015 - December 2015

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	7032	3516
+ 9	6329	3164
+ 8	5626	2813
+ 7	4922	2461
+ 6	4219	2110
+ 5	3516	1758
+ 4	2813	1406
+ 3	2110	1055
+ 2	1406	703
+ 1	703	352
0	0	0
- 1	-706	-353
- 2	-1412	-706
- 3	-2119	-1059
- 4	-2825	-1412
- 5	-3531	-1766
- 6	-4237	-2119
- 7	-4943	-2472
- 8	-5650	-2825
- 9	-6356	-3178
- 10	-7062	-3531
	Minimum Attainable Fuel Loss	Maximum Incentive Dollars Allowed by Commission During Period (Penalty)

Issued by: S. W. Connally, Jr.

Generating Performance Incentive Factor

Calculation of Maximum Allowed Incentive Dollars

Actual

Gulf Power Company

Period of: January 2015 - December 2015

Line 1	Beginning of Period Balance of Common Equity	$1,309,589,940
	End of Month Balance of Common Equity:	
Line 2	Month of Jan '15	$1,316,502,793
Line 3	Month of Feb '15	$1,326,830,138
Line 4	Month of Mar '15	$1,336,693,528
Line 5	Month of Apr '15	$1,310,072,616
Line 6	Month of May '15	$1,323,077,186
Line 7	Month of Jun '15	$1,340,235,742
Line 8	Month of Jul '15	$1,324,832,425
Line 9	Month of Aug '15	$1,343,227,516
Line 10	Month of Sep '15	$1,357,153,825
Line 11	Month of Oct '15	$1,334,707,592
Line 12	Month of Nov '15	$1,345,337,204
Line 13	Month of Dec '15	$1,354,664,607
Line 14	Average Common Equity for the Period (sum of line 1 through line 13 divided by 13)	$1,332,532,701
Line 15	25 Basis Points	0.0025
Line 16	Revenue Expansion Factor	61.1928%
Line 17	Maximum Allowed Incentive Dollars (line 14 multiplied by line 15 divided by line 16 multiplied by 1.0)	$5,443,993
Line 18	Jurisdictional Sales (KWH)	11,085,871,921
Line 19	Total Territorial Sales (KWH)	11,400,418,886
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	97.2409%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 multiplied by line 20)	$5,293,789
Line 22	Incentive Cap (50% of Projected Fuel Savings at 10 GPIF point level from sheet 7.377.6)	$3,516,000
Line 23	Maximum Allowed GPIF Reward (at 10 GPIF Pt. level) (The lesser of Line 21 and Line 22)	$3,516,000

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Calculation of System Actual GPIF Points

Gulf Power Company

Period of: January 2015 - December 2015

Plant & Unit	Performance Indicator (EAF or ANOHR)	Weighting Factor	Unit Points	Weighted Unit Points
Crist 6	EAF3	0.0%	4.00	0.000
Crist 6	ANOHR3	2.1%	-0.20	-0.004
Crist 7	EAF4	0.0%	4.55	0.000
Crist 7	ANOHR4	18.2%	7.58	1.380
Daniel 1	EAF5	0.6%	10.00	0.064
Daniel 1	ANOHR5	10.1%	-3.90	-0.393
Daniel 2	EAF6	0.5%	10.00	0.054
Daniel 2	ANOHR6	13.5%	-10.00	-1.345
Smith 3	EAF7	1.9%	5.71	0.111
Smith 3	ANOHR7	53.0%	0.00	0.000
Gulf Power GPIF Total		100.0%		-0.13

Issued by: S. W. Connally, Jr.

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2015 - December 2015

Crist 6

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	81.60	+ 10	150	12,157
+ 9	0	81.55	+ 9	135	12,187
+ 8	0	81.50	+ 8	120	12,217
+ 7	0	81.45	+ 7	105	12,247
+ 6	0	81.40	+ 6	90	12,277
+ 5	0	81.35	+ 5	75	12,308
+ 4	0	81.30	+ 4	60	12,338
+ 3	0	81.25	+ 3	45	12,368
+ 2	0	81.20	+ 2	30	12,398
+ 1	0	81.15	+ 1	15	12,428
				0	12,458
0	0	81.10	0	0	12,533
				0	12,608
- 1	0	81.08	- 1	(15)	12,638
- 2	0	81.06	- 2	(30)	12,668
- 3	0	81.04	- 3	(45)	12,698
- 4	0	81.02	- 4	(60)	12,728
- 5	0	81.00	- 5	(75)	12,759
- 6	0	80.98	- 6	(90)	12,789
- 7	0	80.96	- 7	(105)	12,819
- 8	0	80.94	- 8	(120)	12,849
- 9	0	80.92	- 9	(135)	12,879
- 10	0	80.90	- 10	(150)	12,909
Weighting Factor:		0.000	Weighting Factor:		0.021

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2015 - December 2015

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	0	96.00	+ 10	1,280	10,563
+ 9	0	95.89	+ 9	1,152	10,588
+ 8	0	95.78	+ 8	1,024	10,613
+ 7	0	95.67	+ 7	896	10,639
+ 6	0	95.56	+ 6	768	10,664
+ 5	0	95.45	+ 5	640	10,689
+ 4	0	95.34	+ 4	512	10,714
+ 3	0	95.23	+ 3	384	10,739
+ 2	0	95.12	+ 2	256	10,765
+ 1	0	95.01	+ 1	128	10,790
				0	10,815
0	0	94.90	0	0	10,890
				0	10,965
- 1	0	94.80	- 1	(128)	10,990
- 2	0	94.70	- 2	(256)	11,015
- 3	0	94.60	- 3	(384)	11,041
- 4	0	94.50	- 4	(512)	11,066
- 5	0	94.40	- 5	(640)	11,091
- 6	0	94.30	- 6	(768)	11,116
- 7	0	94.20	- 7	(896)	11,141
- 8	0	94.10	- 8	(1,024)	11,167
- 9	0	94.00	- 9	(1,152)	11,192
- 10	0	93.90	- 10	(1,280)	11,217
Weighting Factor:		0.000	Weighting Factor:		0.182

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2015 - December 2015

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	45	75.00	+ 10	708	10,055
+ 9	41	74.83	+ 9	637	10,079
+ 8	36	74.66	+ 8	566	10,102
+ 7	32	74.49	+ 7	496	10,126
+ 6	27	74.32	+ 6	425	10,149
+ 5	23	74.15	+ 5	354	10,173
+ 4	18	73.98	+ 4	283	10,197
+ 3	14	73.81	+ 3	212	10,220
+ 2	9	73.64	+ 2	142	10,244
+ 1	5	73.47	+ 1	71	10,267
				0	10,291
0	0	73.30	0	0	10,366
				0	10,441
- 1	(10)	72.88	- 1	(71)	10,465
- 2	(19)	72.46	- 2	(142)	10,488
- 3	(29)	72.04	- 3	(212)	10,512
- 4	(38)	71.62	- 4	(283)	10,535
- 5	(48)	71.20	- 5	(354)	10,559
- 6	(58)	70.78	- 6	(425)	10,583
- 7	(67)	70.36	- 7	(496)	10,606
- 8	(77)	69.94	- 8	(566)	10,630
- 9	(86)	69.52	- 9	(637)	10,653
- 10	(96)	69.10	- 10	(708)	10,677
Weighting Factor:		0.006	Weighting Factor:		0.101

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2015 - December 2015

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	38	89.90	+ 10	946	9,890
+ 9	34	89.78	+ 9	851	9,913
+ 8	30	89.66	+ 8	757	9,936
+ 7	27	89.54	+ 7	662	9,959
+ 6	23	89.42	+ 6	568	9,982
+ 5	19	89.30	+ 5	473	10,006
+ 4	15	89.18	+ 4	378	10,029
+ 3	11	89.06	+ 3	284	10,052
+ 2	8	88.94	+ 2	189	10,075
+ 1	4	88.82	+ 1	95	10,098
				0	10,121
0	0	88.70	0	0	10,196
				0	10,271
- 1	(7)	88.26	- 1	(95)	10,294
- 2	(14)	87.82	- 2	(189)	10,317
- 3	(20)	87.38	- 3	(284)	10,340
- 4	(27)	86.94	- 4	(378)	10,363
- 5	(34)	86.50	- 5	(473)	10,387
- 6	(41)	86.06	- 6	(568)	10,410
- 7	(48)	85.62	- 7	(662)	10,433
- 8	(54)	85.18	- 8	(757)	10,456
- 9	(61)	84.74	- 9	(851)	10,479
- 10	(68)	84.30	- 10	(946)	10,502
Weighting Factor:		0.005	Weighting Factor:		0.135

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2015 - December 2015

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	137	93.40	+ 10	3,728	6,646
+ 9	123	93.33	+ 9	3,355	6,659
+ 8	110	93.26	+ 8	2,982	6,672
+ 7	96	93.19	+ 7	2,610	6,685
+ 6	82	93.12	+ 6	2,237	6,698
+ 5	69	93.05	+ 5	1,864	6,712
+ 4	55	92.98	+ 4	1,491	6,725
+ 3	41	92.91	+ 3	1,118	6,738
+ 2	27	92.84	+ 2	746	6,751
+ 1	14	92.77	+ 1	373	6,764
				0	6,777
0	0	92.70	0	0	6,852
				0	6,927
- 1	(9)	92.59	- 1	(373)	6,940
- 2	(17)	92.48	- 2	(746)	6,953
- 3	(26)	92.37	- 3	(1,118)	6,966
- 4	(34)	92.26	- 4	(1,491)	6,979
- 5	(43)	92.15	- 5	(1,864)	6,993
- 6	(52)	92.04	- 6	(2,237)	7,006
- 7	(60)	91.93	- 7	(2,610)	7,019
- 8	(69)	91.82	- 8	(2,982)	7,032
- 9	(77)	91.71	- 9	(3,355)	7,045
- 10	(86)	91.60	- 10	(3,728)	7,058
Weighting Factor:		0.019	Weighting Factor:		0.530

Issued by: S. W. Connally, Jr.

GPIF Unit Performance Summary

Gulf Power Company

Period of: January 2015 - December 2015

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)
Crist 6	0.0	81.1	81.6	80.9	$0	$0	81.3	$0
Crist 7	0.0	94.9	96.0	93.9	$0	$0	95.4	$0
Daniel 1	0.6	73.3	75.0	69.1	$45	($96)	79.4	$45
Daniel 2	0.5	88.7	89.9	84.3	$38	($68)	94.2	$38
Smith 3	1.9	92.7	93.4	91.6	$137	($86)	93.1	$78
Total:	3.1							

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)
Crist 6	2.1	12,533	41.7	12,909	12,157	$150	($150)	12,614	($3)
Crist 7	18.2	10,890	58.4	11,217	10,563	$1,280	($1,280)	10,624	$970
Daniel 1	10.1	10,366	65.1	10,677	10,055	$708	($708)	10,533	($276)
Daniel 2	13.5	10,196	66.0	10,502	9,890	$946	($946)	10,658	($946)
Smith 3	53.0	6,852	83.9	7,058	6,646	$3,728	($3,728)	6,892	$0
Total:	96.9								

Issued by: S. W. Connally, Jr.

Actual Unit Performance Data

Gulf Power Company

Period of: January 2015 - December 2015

Plant & Unit	Actual EAF %	Adjustments* to EAF %	Adjusted Actual %
Crist 6	81.0	0.3	81.3
Crist 7	88.3	7.1	95.4
Daniel 1	75.6	3.8	79.4
Daniel 2	93.5	0.7	94.2
Smith 3	92.3	0.8	93.1

Plant & Unit	Actual ANOHR BTU/KWH	Adjustments** to ANOHR BTU/KWH	ANOHR Adjusted Actual BTU/KWH
Crist 6	11,115	1499	12,614
Crist 7	10,669	-45	10,624
Daniel 1	10,765	-232	10,533
Daniel 2	10,825	-167	10,658
Smith 3	6,901	-9	6,892

* Refer to pages 4 through 8, Schedule 2.

** Refer to pages 7 through 11, Schedule 3.

Issued by: S. W. Connally, Jr.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2015 - December 2015

	CRIST 6	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15	
1.	EAF (%)	99.9	90.0	87.1	0.0	15.8	99.4	
2.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
3.	SH	161.8	406.0	160.2	0.0	117.2	461.1	
4.	RSH	581.3	266.0	486.8	0.0	0.0	255.5	
5.	UH	0.9	0.0	96.0	720.0	626.8	3.4	
6.	POH	0.0	0.0	96.0	720.0	626.8	0.0	
7.	FOH	0.9	0.0	0.0	0.0	0.0	3.4	
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	
9.	PFOH	0.0	141.9	0.0	0.0	0.0	3.1	
10.	LR pf (MW)	0.0	141.0	0.0	0.0	0.0	104.5	
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)	299.0	299.0	299.0	299.0	299.0	299.0	
14.	Oper MBtu	330029	752276	358290	0	216067	942157	
15.	Net Gen (MWH	28493	70529	30838	0	17788	87284	
16.	ANOHR (Btu/K	11583	10666	11618	0	12147	10794	
17.	NOF %	58.9	58.1	64.4	0.0	50.8	63.3	
18.	NPC (MW)	299.0	299.0	299.0	299.0	299.0	299.0	
19.	ANOHR Equati	10^6 / AKW * [547.85 + 100.05 * JAN + 141.57 * FEB + 147.80 * MAR + 131.25 * APR + 62.34 * AUG + 36.24 * OCT] + 7,054 + 0.00420 * LSRF / AKW						

Issued by: S. W. Connally, Jr.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2015 - December 2015

	CRIST 6	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1.	EAF (%)	100.0	93.0	99.7	87.0	100.0	100.0	81.0
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
3.	SH	505.5	172.0	497.7	167.2	0.0	0.0	2648.7
4.	RSH	238.5	520.2	219.8	480.2	721.0	744.0	4513.3
5.	UH	0.0	51.9	2.5	96.6	0.0	0.0	1598.1
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1442.8
7.	FOH	0.0	0.0	2.5	0.0	0.0	0.0	6.8
8.	MOH	0.0	51.9	0.0	96.6	0.0	0.0	148.5
9.	PFOH	0.4	0.0	0.0	0.0	0.0	0.0	145.4
10.	LR pf (MW)	139.0	0.0	0.0	0.0	0.0	0.0	140.2
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13.	NSC (MW)	299.0	299.0	299.0	299.0	299.0	299.0	299.0
14.	Oper MBtu	1065813	326608	952377	318248	0	0	5261865
15.	Net Gen (MWH	97019	29956	83095	28381	0	0	473383
16.	ANOHR (Btu/K	10986	10903	11461	11213	0	0	11115
17.	NOF %	64.2	58.3	55.8	56.8	0.0	0.0	59.8
18.	NPC (MW)	299.0	299.0	299.0	299.0	299.0	299.0	299.0

19.	ANOHR Equati	10^6 / AKW * [547.85 + 100.05 * JAN + 141.57 * FEB + 147.80 * MAR + 131.25 * APR + 62.34 * AUG + 36.24 * OCT] + 7,054 + 0.00420 * LSRF / AKW

Issued by: S. W. Connally, Jr.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2015 - December 2015

	CRIST 7	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15	
1.	EAF (%)	96.7	89.9	100.0	46.5	100.0	98.7	
2.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
3.	SH	697.8	604.3	743.0	339.3	744.0	716.5	
4.	RSH	44.3	0.0	0.0	0.0	0.0	0.0	
5.	UH	1.9	67.7	0.0	380.7	0.0	3.5	
6.	POH	0.0	0.0	0.0	207.2	0.0	0.0	
7.	FOH	1.9	0.0	0.0	0.0	0.0	3.5	
8.	MOH	0.0	67.7	0.0	173.5	0.0	0.0	
9.	PFOH	40.7	0.0	0.0	0.0	0.0	0.0	
10.	LR pf (MW)	225.0	0.0	0.0	0.0	0.0	0.0	
11.	PMOH	15.5	0.0	0.0	17.9	0.0	14.0	
12.	LR pm (MW)	100.0	0.0	0.0	117.0	0.0	195.0	
13.	NSC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	
14.	Oper MBtu	1850209	1690592	2032405	888714	2270379	2345773	
15.	Net Gen (MWH	179147	160821	187050	80425	217393	218145	
16.	ANOHR (Btu/K	10328	10512	10866	11050	10444	10753	
17.	NOF %	54.0	56.0	53.0	49.9	61.5	64.1	
18.	NPC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	
19.	ANOHR Equati	10^6 / AKW * [735.33 - 74.26 * MAR + 77.66 * APR] + 7,097 + 0.00393 * LSRF / AKW						

Issued by: S. W. Connally, Jr.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2015 - December 2015

	CRIST 7	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1.	EAF (%)	98.2	89.1	100.0	54.8	84.7	100.0	88.3
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
3.	SH	744.0	662.6	720.0	387.7	170.6	0.0	6529.8
4.	RSH	0.0	0.0	0.0	20.3	440.4	744.0	1249.0
5.	UH	0.0	81.4	0.0	336.0	110.0	0.0	981.2
6.	POH	0.0	0.0	0.0	336.0	107.8	0.0	651.0
7.	FOH	0.0	0.0	0.0	0.0	2.2	0.0	7.6
8.	MOH	0.0	81.4	0.0	0.0	0.0	0.0	322.6
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	40.7
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	225.0
11.	PMOH	32.4	0.0	0.0	0.0	0.0	0.0	79.8
12.	LR pm (MW)	195.0	0.0	0.0	0.0	0.0	0.0	159.1
13.	NSC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	475.0
14.	Oper MBtu	2647334	2156414	2047628	1052549	439384	0	19421381
15.	Net Gen (MWH	245198	202372	193205	96246	40396	0	1820398
16.	ANOHR (Btu/K	10797	10656	10598	10936	10877	0	10669
17.	NOF %	69.4	64.3	56.5	52.3	49.9	0.0	58.7
18.	NPC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	475.0
19.	ANOHR Equati	10^6 / AKW * [735.33 - 74.26 * MAR + 77.66 * APR] + 7,097 + 0.00393 * LSRF / AKW						

Issued by: S. W. Connally, Jr.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2015 - December 2015

	DANIEL 1	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15	
1.	EAF (%)	51.5	0.0	0.0	74.3	99.4	91.5	
2.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
3.	SH	111.2	0.0	0.0	393.9	742.7	663.6	
4.	RSH	272.8	0.0	0.0	141.6	0.0	0.0	
5.	UH	360.0	672.0	743.0	184.5	1.3	56.4	
6.	POH	360.0	672.0	743.0	179.5	0.0	0.0	
7.	FOH	0.0	0.0	0.0	5.0	1.3	5.3	
8.	MOH	0.0	0.0	0.0	0.0	0.0	51.1	
9.	PFOH	1.9	0.0	0.0	1.1	9.4	15.8	
10.	LR pf (MW)	171.6	0.0	0.0	210.0	187.9	149.6	
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)	510.0	510.0	510.0	510.0	510.0	510.0	
14.	Oper MBtu	239733	0	0	1200656	2387571	1966004	
15.	Net Gen (MWH	23099	0	0	100571	212167	183189	
16.	ANOHR (Btu/K	10379	0	0	11938	11253	10732	
17.	NOF %	40.7	0.0	0.0	50.1	56.0	54.1	
18.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	
19.	ANOHR Equati	10^6 / AKW * [338.36 + 79.10 * MAY + 137.43 * OCT + 89.35 * NOV] + 9,278						

Issued by: S. W. Connally, Jr.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2015 - December 2015

	DANIEL 1	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1.	EAF (%)	100.0	85.2	100.0	100.0	100.0	100.0	75.6
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
3.	SH	744.0	635.3	238.3	0.0	318.2	0.0	3847.2
4.	RSH	0.0	0.0	481.7	744.0	402.8	744.0	2786.9
5.	UH	0.0	108.7	0.0	0.0	0.0	0.0	2125.9
6.	POH	0.0	108.7	0.0	0.0	0.0	0.0	2063.2
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	11.6
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	51.1
9.	PFOH	0.0	4.7	0.0	0.0	0.8	0.0	33.7
10.	LR pf (MW)	0.0	125.0	0.0	0.0	165.0	0.0	160.4
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13.	NSC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	510.0
14.	Oper MBtu	2393066	1958161	638694	0	687015	0	11470900
15.	Net Gen (MWH	235565	186808	64999	0	59205	0	1065603
16.	ANOHR (Btu/K	10159	10482	9826	0	11604	0	10765
17.	NOF %	62.1	57.7	53.5	0.0	36.5	0.0	54.3
18.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	510.0
19.	ANOHR Equati	10^6 / AKW * [338.36 + 79.10 * MAY + 137.43 * OCT + 89.35 * NOV] + 9,278						

Issued by: S. W. Connally, Jr.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2015 - December 2015

	DANIEL 2	Jan '15	Feb '15	Mar '15	Apr '15	May '15	Jun '15	
1.	EAF (%)	71.0	98.1	70.9	98.8	99.1	98.3	
2.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
3.	SH	145.0	385.5	159.2	384.2	619.2	707.8	
4.	RSH	383.0	276.1	367.8	328.5	123.1	0.0	
5.	UH	216.0	10.4	216.0	7.3	1.7	12.2	
6.	POH	216.0	0.0	216.0	1.4	0.0	0.0	
7.	FOH	0.0	10.4	0.0	5.9	1.7	2.5	
8.	MOH	0.0	0.0	0.0	0.0	0.0	9.7	
9.	PFOH	0.0	11.0	0.0	3.1	12.1	0.0	
10.	LR pf (MW)	0.0	121.2	0.0	230.0	215.4	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)	510.0	510.0	510.0	510.0	510.0	510.0	
14.	Oper MBtu	398815	905150	302829	1010488	2070643	2330976	
15.	Net Gen (MWH	31796	82140	29549	95157	175060	200812	
16.	ANOHR (Btu/K	12543	11020	10248	10619	11828	11608	
17.	NOF %	43.0	41.8	36.4	48.6	55.4	55.6	
18.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	
19.	ANOHR Equati	10^6 / AKW * [430.73 - 94.68 * JAN - 274.79 * FEB + 67.80 * MAR + 155.49 * OCT] + 8,937						

Issued by: S. W. Connally, Jr.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2015 - December 2015

	DANIEL 2	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1.	EAF (%)	99.1	100.0	87.5	100.0	100.0	99.5	93.5
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
3.	SH	737.5	744.0	470.4	214.6	114.4	133.1	4814.9
4.	RSH	0.0	0.0	159.7	529.4	606.6	606.9	3381.1
5.	UH	6.5	0.0	89.9	0.0	0.0	4.0	564.0
6.	POH	0.0	0.0	89.9	0.0	0.0	0.0	523.3
7.	FOH	3.3	0.0	0.0	0.0	0.0	4.0	27.8
8.	MOH	3.2	0.0	0.0	0.0	0.0	0.0	12.9
9.	PFOH	2.9	0.4	5.8	0.0	0.0	0.0	35.3
10.	LR pf (MW)	15.8	50.0	35.0	0.0	0.0	0.0	139.4
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13.	NSC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	510.0
14.	Oper MBtu	2545121	2965525	1594188	447804	205259	448774	15225572
15.	Net Gen (MWH	245916	292620	153673	44201	18442	37173	1406539
16.	ANOHR (Btu/K	10350	10134	10374	10131	11130	12073	10825
17.	NOF %	65.4	77.1	64.1	40.4	31.6	54.8	57.3
18.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	510.0
19.	ANOHR Equati	10^6 / AKW * [430.73 - 94.68 * JAN - 274.79 * FEB + 67.80 * MAR + 155.49 * OCT] + 8,937						

Issued by: S. W. Connally, Jr.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2015 - December 2015

	SMITH 3	Jan '14	Feb '15	Mar '15	Apr '15	May '15	Jun '15	
1.	EAF (%)	99.6	99.0	70.4	99.5	94.2	90.5	
2.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
3.	SH	744.0	658.8	523.4	686.0	648.6	610.1	
4.	RSH	0.0	8.6	0.0	34.0	52.3	41.3	
5.	UH	0.0	4.6	219.6	0.0	43.1	68.6	
6.	POH	0.0	0.0	219.6	0.0	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	MOH	0.0	4.6	0.0	0.0	43.1	68.6	
9.	PFOH	0.0	4.8	0.0	7.6	0.0	0.0	
10.	LR pf (MW)	0.0	266.0	0.0	239.0	0.0	0.0	
11.	PMOH	6.2	0.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	266.0	0.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	584.0	584.0	558.0	558.0	558.0	556.0	
14.	Oper MBtu	2474151	2210303	1546370	2140768	2119315	1986146	
15.	Net Gen (MWH	359330	321535	221511	311321	306763	286484	
16.	ANOHR (Btu/K	6885	6874	6981	6876	6909	6933	
17.	NOF %	75.6	83.6	75.8	81.3	84.8	84.5	
18.	NPC (MW)	584.0	584.0	558.0	558.0	558.0	556.0	
19.	ANOHR Equati	10^6 / AKW * [314.69 - 33.91 * OCT] + 6,195						

Issued by: S. W. Connally, Jr.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2015 - December 2015

	SMITH 3	Jul '15	Aug '15	Sep '15	Oct '15	Nov '15	Dec '15	Total
1.	EAF (%)	97.9	100.0	99.7	100.0	58.4	98.1	92.3
2.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
3.	SH	744.0	736.2	672.4	744.0	354.9	664.3	7786.7
4.	RSH	0.0	7.8	47.6	0.0	74.2	74.1	339.9
5.	UH	0.0	0.0	0.0	0.0	291.9	5.6	633.4
6.	POH	0.0	0.0	0.0	0.0	291.9	0.0	511.5
7.	FOH	0.0	0.0	0.0	0.0	0.0	5.6	5.6
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	116.3
9.	PFOH	0.0	0.0	8.7	0.0	13.0	0.0	34.1
10.	LR pf (MW)	0.0	0.0	160.0	0.0	226.8	0.0	218.0
11.	PMOH	36.7	0.0	0.0	0.0	8.6	18.4	69.9
12.	LR pm (MW)	239.0	0.0	0.0	0.0	179.0	266.0	241.1
13.	NSC (MW)	556.0	556.0	556.0	558.0	558.0	584.0	563.8
14.	Oper MBtu	2331163	2355662	2170720	2512797	1150182	2126033	25123611
15.	Net Gen (MWH	335751	340084	313758	370708	166496	306985	3640726
16.	ANOHR (Btu/K	6943	6927	6918	6778	6908	6926	6901
17.	NOF %	81.2	83.1	83.9	89.3	84.1	79.1	82.9
18.	NPC (MW)	556.0	556.0	556.0	558.0	558.0	584.0	563.8
19.	ANOHR Equati	10^6 / AKW * [314.69 - 33.91 * OCT] + 6,195						

Issued by: S. W. Connally, Jr.

Planned Outage Schedules (Actual)

Period of: January 2015 - December 2015

Critical path bar charts of actual work activity performed during major planned outages are not shown here since corresponding bar charts of forecast work activity were not provided earlier in conformance with agreement with Staff to avoid the premature production of charts prior to their normal course of development. Forecast and actual critical path bar charts are developed for each planned outage and, per agreement with Staff, these charts will be provided on request.

Issued by: S. W. Connally, Jr.

EXHIBIT TO THE TESTIMONY OF

C. L. NICHOLSON

IN FPSC DOCKET 160001-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 48
PARTY: GULF POWER COMPANY – (DIRECT)
DESCRIPTION: C. L. Nicholson CLN-2

I. DETERMINATION OF HEAT RATE TARGETS

Target Heat Rate Equations

Scherer 3 ANOHR = 10^6 / AKW * [546.07 + 67.96 * FEB - 86.35 * MAR + 101.88 * MAY]
+ 9,691

Crist 7 ANOHR = 10^6 / AKW * [289.45 - 65.63 * JAN - 47.70 * FEB + 85.87 * APR + 114.25 * JUN + 68.08 * JUL + 66.42 * AUG]
+ 9,556

Daniel 1 ANOHR = 10^6 / AKW * [190.55 + 259.92 * APR + 111.26 * MAY + 74.52 * JUN + 183.30 * OCT + 100.15 * NOV]
+ 9,760

Daniel 2 ANOHR = 10^6 / AKW * [575.65 - 103.95 * FEB - 185.22 * MAR + 105.27 * JUN - 106.15 * NOV]
+ 8,491

Smith 3 ANOHR = 10^6 / AKW * [21.08 + 44.81 * FEB + 27.39 * MAR + 36.15 * APR + 45.63 * MAY + 55.90 * JUN - 43.01 * OCT]
+ 6,850

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	
10546	168	595.13	414928	0	0	0	0	0	0	1	0	0	0	0	0	2013	JUL
10649	168	608.97	433882	0	0	0	0	0	0	1	0	0	0	0	0	2013	
10497	168	634.40	462806	0	0	0	0	0	0	1	0	0	0	0	0	2013	
10693	168	612.16	438457	0	0	0	0	0	0	1	0	0	0	0	0	2013	
10730	168	612.55	436378	0	0	0	0	0	0	0	1	0	0	0	0	2013	
10726	168	642.44	471353	0	0	0	0	0	0	0	1	0	0	0	0	2013	
10960	168	510.99	306540	0	0	0	0	0	0	0	1	0	0	0	0	2013	
10855	94	585.68	231620	0	0	0	0	0	0	0	1	0	0	0	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	1	0	0	0	0	2013	
10861	153	456.89	220148	0	0	0	0	0	0	0	0	1	0	0	1	2013	
10638	168	625.21	446800	0	0	0	0	0	0	0	0	1	0	0	0	2013	
10725	168	638.13	459605	0	0	0	0	0	0	0	0	1	0	0	0	2013	
10908	168	578.12	389696	0	0	0	0	0	0	0	0	1	0	0	0	2013	
10202	168	625.38	448138	0	0	0	0	0	0	0	0	0	1	0	0	2013	
10467	168	676.71	506361	0	0	0	0	0	0	0	0	0	1	0	0	2013	
10429	168	676.51	506285	0	0	0	0	0	0	0	0	0	1	0	0	2013	
10474	168	721.79	561077	0	0	0	0	0	0	0	0	0	1	0	0	2013	
10634	168	584.77	402647	0	0	0	0	0	0	0	0	0	1	0	0	2013	
10667	168	582.26	390129	0	0	0	0	0	0	0	0	0	0	1	0	2013	
10276	168	621.44	414743	0	0	0	0	0	0	0	0	0	0	1	0	2013	
10289	168	652.94	460819	0	0	0	0	0	0	0	0	0	0	1	0	2013	
10277	168	667.10	477053	0	0	0	0	0	0	0	0	0	0	1	0	2013	
10395	165	606.58	407742	0	0	0	0	0	0	0	0	0	0	0	0	2013	DEC
10154	168	755.05	599195	0	0	0	0	0	0	0	0	0	0	0	0	2013	
10374	168	677.48	496623	0	0	0	0	0	0	0	0	0	0	0	0	2013	
10609	168	629.47	441761	0	0	0	0	0	0	0	0	0	0	0	0	2013	
10709	168	756.81	601134	1	0	0	0	0	0	0	0	0	0	0	0	2014	JAN
10655	168	613.00	425863	1	0	0	0	0	0	0	0	0	0	0	0	2014	
10478	168	719.18	553424	1	0	0	0	0	0	0	0	0	0	0	0	2014	
10509	168	782.67	635736	1	0	0	0	0	0	0	0	0	0	0	0	2014	
10474	168	783.11	636841	0	1	0	0	0	0	0	0	0	0	0	0	2014	
10503	168	723.32	535005	0	1	0	0	0	0	0	0	0	0	0	0	2014	
10903	113	567.23	265265	0	1	0	0	0	0	0	0	0	0	0	1	2014	
10511	168	773.38	624338	0	1	0	0	0	0	0	0	0	0	0	0	2014	
10248	144	789.23	551389	0	0	1	0	0	0	0	0	0	0	0	0	2014	
10274	167	710.90	542929	0	0	1	0	0	0	0	0	0	0	0	0	2014	
10538	168	593.09	402093	0	0	1	0	0	0	0	0	0	0	0	0	2014	
11013	168	369.88	164858	0	0	1	0	0	0	0	0	0	0	0	0	2014	
11294	168	317.67	104117	0	0	1	0	0	0	0	0	0	0	0	0	2014	
11437	168	308.25	95020	0	0	0	1	0	0	0	0	0	0	0	0	2014	
11034	168	414.70	208491	0	0	0	1	0	0	0	0	0	0	0	0	2014	
10970	77	351.35	73327	0	0	0	1	0	0	0	0	0	0	0	1	2014	
10676	168	570.68	372021	0	0	0	1	0	0	0	0	0	0	0	0	2014	
10506	168	586.00	379821	0	0	0	0	1	0	0	0	0	0	0	0	2014	
10569	168	595.96	396958	0	0	0	0	1	0	0	0	0	0	0	0	2014	
10488	159	598.40	383368	0	0	0	0	1	0	0	0	0	0	0	0	2014	
10677	168	544.52	344465	0	0	0	0	1	0	0	0	0	0	0	0	2014	
10507	168	615.81	426860	0	0	0	0	1	0	0	0	0	0	0	0	2014	
10557	168	662.15	482837	0	0	0	0	0	1	0	0	0	0	0	0	2014	
10687	168	597.61	405898	0	0	0	0	0	1	0	0	0	0	0	0	2014	
10595	168	646.73	470399	0	0	0	0	0	1	0	0	0	0	0	0	2014	
10587	168	623.04	441054	0	0	0	0	0	1	0	0	0	0	0	0	2014	
11140	168	615.27	434428	0	0	0	0	0	0	1	0	0	0	0	0	2014	

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	
10885	165	624.32	442508	0	0	0	0	0	0	1	0	0	0	0	0	2014	JUL
10771	168	481.25	276606	0	0	0	0	0	0	1	0	0	0	0	0	2014	
10448	168	629.71	453293	0	0	0	0	0	0	1	0	0	0	0	0	2014	
10500	168	578.29	394099	0	0	0	0	0	0	0	1	0	0	0	0	2014	
10739	168	538.54	341290	0	0	0	0	0	0	0	1	0	0	0	0	2014	
11042	168	514.49	310081	0	0	0	0	0	0	0	1	0	0	0	0	2014	
10984	168	566.71	378203	0	0	0	0	0	0	0	1	0	0	0	0	2014	
10774	168	556.72	370409	0	0	0	0	0	0	0	1	0	0	0	0	2014	
10638	168	587.61	404528	0	0	0	0	0	0	0	0	1	0	0	0	2014	
10584	168	532.53	332214	0	0	0	0	0	0	0	0	1	0	0	0	2014	
11029	168	482.73	264704	0	0	0	0	0	0	0	0	1	0	0	0	2014	
10848	145	449.57	200778	0	0	0	0	0	0	0	0	1	0	0	0	2014	
10959	165	533.24	322211	0	0	0	0	0	0	0	0	0	1	0	0	2014	
10529	168	603.48	398486	0	0	0	0	0	0	0	0	0	1	0	0	2014	
11178	168	407.32	184539	0	0	0	0	0	0	0	0	0	1	0	0	2014	
11101	168	402.63	179660	0	0	0	0	0	0	0	0	0	1	0	0	2014	
11048	168	396.23	173427	0	0	0	0	0	0	0	0	0	1	0	0	2014	
11284	168	405.97	180430	0	0	0	0	0	0	0	0	0	0	1	0	2014	
10797	168	647.46	469412	0	0	0	0	0	0	0	0	0	0	1	0	2014	
10815	168	617.15	428615	0	0	0	0	0	0	0	0	0	0	1	0	2014	
11116	168	437.03	227924	0	0	0	0	0	0	0	0	0	0	1	0	2014	
10939	70	421.84	90993	0	0	0	0	0	0	0	0	0	0	0	0	2014	DEC
10721	31	716.55	125714	0	0	0	0	0	0	0	0	0	0	0	1	2014	
10657	168	489.26	274234	0	0	0	0	0	0	0	0	0	0	0	0	2014	
11480	168	334.02	118203	0	0	0	0	0	0	0	0	0	0	0	0	2014	
11016	168	378.18	163220	1	0	0	0	0	0	0	0	0	0	0	0	2015	JAN
10995	168	461.85	255166	1	0	0	0	0	0	0	0	0	0	0	0	2015	
10843	168	486.92	292172	1	0	0	0	0	0	0	0	0	0	0	0	2015	
11175	168	431.68	224295	1	0	0	0	0	0	0	0	0	0	0	0	2015	
11067	168	440.23	230647	0	1	0	0	0	0	0	0	0	0	0	0	2015	
11287	168	401.79	192336	0	1	0	0	0	0	0	0	0	0	0	0	2015	
10870	168	536.42	344942	0	1	0	0	0	0	0	0	0	0	0	0	2015	
10457	168	797.71	657144	0	1	0	0	0	0	0	0	0	0	0	0	2015	
10416	144	753.37	516953	0	0	1	0	0	0	0	0	0	0	0	0	2015	
10180	71	710.41	236391	0	0	1	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2015	
*18180	9	186.33	5855	0	0	0	0	1	0	0	0	0	0	0	1	2015	
11313	168	625.54	441802	0	0	0	0	1	0	0	0	0	0	0	0	2015	
11625	168	499.21	294687	0	0	0	0	1	0	0	0	0	0	0	0	2015	
11124	168	521.91	330569	0	0	0	0	1	0	0	0	0	0	0	0	2015	
10748	168	564.07	376848	0	0	0	0	0	1	0	0	0	0	0	0	2015	
10647	168	589.92	412245	0	0	0	0	0	1	0	0	0	0	0	0	2015	
10530	168	643.70	475057	0	0	0	0	0	1	0	0	0	0	0	0	2015	
10837	168	563.89	379004	0	0	0	0	0	1	0	0	0	0	0	0	2015	
*12341	168	491.64	291905	0	0	0	0	0	0	1	0	0	0	0	0	2015	JUL
10205	168	643.59	474928	0	0	0	0	0	0	1	0	0	0	0	0	2015	

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	
10225	168	619.36	447746	0	0	0	0	0	0	1	0	0	0	0	0	2015	
9935	168	622.98	451472	0	0	0	0	0	0	1	0	0	0	0	0	2015	
10377	168	612.35	437624	0	0	0	0	0	0	0	1	0	0	0	0	2015	
10393	168	627.54	454636	0	0	0	0	0	0	0	1	0	0	0	0	2015	
10574	168	584.23	400959	0	0	0	0	0	0	0	1	0	0	0	0	2015	
10790	168	569.36	386842	0	0	0	0	0	0	0	1	0	0	0	0	2015	
10753	168	491.89	293031	0	0	0	0	0	0	0	1	0	0	0	0	2015	
*14164	168	567.29	376786	0	0	0	0	0	0	0	0	1	0	0	0	2015	
* 9831	168	454.12	247242	0	0	0	0	0	0	0	0	1	0	0	0	2015	
* 9460	168	493.68	281671	0	0	0	0	0	0	0	0	1	0	0	0	2015	
* 9561	168	508.58	303489	0	0	0	0	0	0	0	0	1	0	0	0	2015	
10523	168	490.82	287487	0	0	0	0	0	0	0	0	0	1	0	0	2015	
10810	168	480.65	269091	0	0	0	0	0	0	0	0	0	1	0	0	2015	
11558	168	317.83	102882	0	0	0	0	0	0	0	0	0	1	0	0	2015	
11352	168	327.78	109800	0	0	0	0	0	0	0	0	0	1	0	0	2015	
11032	168	343.42	124242	0	0	0	0	0	0	0	0	0	1	0	0	2015	
10505	168	351.90	134131	0	0	0	0	0	0	0	0	0	0	1	0	2015	
11719	168	359.02	141144	0	0	0	0	0	0	0	0	0	0	1	0	2015	
10430	50	425.34	73757	0	0	0	0	0	0	0	0	0	0	1	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2015	DEC
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2015	
10856	124	390.94	134389	1	0	0	0	0	0	0	0	0	0	0	1	2016	JAN
10632	168	441.46	227514	1	0	0	0	0	0	0	0	0	0	0	0	2016	
10750	168	465.69	265121	1	0	0	0	0	0	0	0	0	0	0	0	2016	
10679	168	481.56	289377	1	0	0	0	0	0	0	0	0	0	0	0	2016	
11534	168	322.86	108959	0	1	0	0	0	0	0	0	0	0	0	0	2016	
11052	168	430.00	229469	0	1	0	0	0	0	0	0	0	0	0	0	2016	
11421	168	351.31	136441	0	1	0	0	0	0	0	0	0	0	0	0	2016	
11570	167	326.07	113501	0	1	0	0	0	0	0	0	0	0	0	0	2016	
11180	168	361.80	143758	0	0	1	0	0	0	0	0	0	0	0	0	2016	
10767	168	420.57	211190	0	0	1	0	0	0	0	0	0	0	0	0	2016	
10309	167	543.48	345347	0	0	1	0	0	0	0	0	0	0	0	0	2016	
10582	168	469.82	251158	0	0	1	0	0	0	0	0	0	0	0	0	2016	
11325	168	318.38	103285	0	0	1	0	0	0	0	0	0	0	0	0	2016	
11487	168	334.78	116735	0	0	0	1	0	0	0	0	0	0	0	0	2016	
11235	18	434.56	31452	0	0	0	1	0	0	0	0	0	0	0	0	2016	
11312	77	342.06	66773	0	0	0	1	0	0	0	0	0	0	0	1	2016	
10766	168	505.95	307986	0	0	0	1	0	0	0	0	0	0	0	0	2016	
11198	168	435.45	226593	0	0	0	0	1	0	0	0	0	0	0	0	2016	
11111	168	474.64	259397	0	0	0	0	1	0	0	0	0	0	0	0	2016	
11122	168	424.15	207820	0	0	0	0	1	0	0	0	0	0	0	0	2016	
11211	168	386.43	170904	0	0	0	0	1	0	0	0	0	0	0	0	2016	
11125	168	454.01	244602	0	0	0	0	1	0	0	0	0	0	0	0	2016	
10937	168	471.55	268839	0	0	0	0	0	1	0	0	0	0	0	0	2016	
10536	168	598.57	418263	0	0	0	0	0	1	0	0	0	0	0	0	2016	
10779	168	521.56	332243	0	0	0	0	0	1	0	0	0	0	0	0	2016	
10660	168	599.39	423335	0	0	0	0	0	1	0	0	0	0	0	0	2016	

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	
10749	168	250.85	63000	0	0	0	0	0	0	1	0	0	0	0	0	2013	JUL
11072	157	254.13	66824	0	0	0	0	0	0	1	0	0	0	0	0	2013	
10907	168	268.24	73675	0	0	0	0	0	0	1	0	0	0	0	0	2013	
10891	119	259.91	49329	0	0	0	0	0	0	1	0	0	0	0	0	2013	
11296	70	269.63	33905	0	0	0	0	0	0	0	1	0	0	0	1	2013	
10966	168	293.89	92308	0	0	0	0	0	0	0	1	0	0	0	0	2013	
11174	168	256.58	67112	0	0	0	0	0	0	0	1	0	0	0	0	2013	
11292	168	261.84	70330	0	0	0	0	0	0	0	1	0	0	0	0	2013	
10264	158	298.56	93956	0	0	0	0	0	0	0	1	0	0	0	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	1	0	0	0	2013	
11182	20	223.95	12085	0	0	0	0	0	0	0	0	1	0	0	2	2013	
10442	166	300.05	97592	0	0	0	0	0	0	0	0	1	0	0	0	2013	
10352	168	302.14	98957	0	0	0	0	0	0	0	0	1	0	0	0	2013	
10548	168	270.57	75107	0	0	0	0	0	0	0	0	0	1	0	0	2013	
10537	168	275.19	78091	0	0	0	0	0	0	0	0	0	1	0	0	2013	
10603	168	260.63	68861	0	0	0	0	0	0	0	0	0	1	0	0	2013	
10522	168	256.17	66102	0	0	0	0	0	0	0	0	0	1	0	0	2013	
10587	169	250.93	63811	0	0	0	0	0	0	0	0	0	1	0	0	2013	
10489	168	255.07	65714	0	0	0	0	0	0	0	0	0	0	1	0	2013	
10542	168	250.29	62810	0	0	0	0	0	0	0	0	0	0	1	0	2013	
10560	168	249.36	62285	0	0	0	0	0	0	0	0	0	0	1	0	2013	
10790	168	252.92	64519	0	0	0	0	0	0	0	0	0	0	1	0	2013	
10118	57	251.82	26943	0	0	0	0	0	0	0	0	0	0	0	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2013	
10321	54	238.65	22443	0	0	0	0	0	0	0	0	0	0	0	1	2013	
10217	167	246.47	61178	0	0	0	0	0	0	0	0	0	0	0	0	2013	
10266	138	286.23	74107	1	0	0	0	0	0	0	0	0	0	0	1	2014	JAN
10248	130	245.63	52186	1	0	0	0	0	0	0	0	0	0	0	1	2014	
10090	168	250.19	62619	1	0	0	0	0	0	0	0	0	0	0	0	2014	
10026	168	258.47	67424	1	0	0	0	0	0	0	0	0	0	0	0	2014	
10172	168	275.49	79595	0	1	0	0	0	0	0	0	0	0	0	0	2014	
10120	168	289.95	89359	0	1	0	0	0	0	0	0	0	0	0	0	2014	
10319	168	276.52	79472	0	1	0	0	0	0	0	0	0	0	0	0	2014	
10751	126	251.57	55128	0	1	0	0	0	0	0	0	0	0	0	1	2014	
10615	168	272.85	78472	0	0	1	0	0	0	0	0	0	0	0	0	2014	
10378	167	282.27	82656	0	0	1	0	0	0	0	0	0	0	0	0	2014	
10228	168	344.69	129508	0	0	1	0	0	0	0	0	0	0	0	0	2014	
11053	168	249.74	62635	0	0	1	0	0	0	0	0	0	0	0	0	2014	
10713	168	248.31	61669	0	0	1	0	0	0	0	0	0	0	0	0	2014	
11026	168	252.86	64756	0	0	0	1	0	0	0	0	0	0	0	0	2014	
10952	168	247.17	61446	0	0	0	1	0	0	0	0	0	0	0	0	2014	
11316	168	249.24	62186	0	0	0	1	0	0	0	0	0	0	0	0	2014	
11250	168	267.09	72718	0	0	0	1	0	0	0	0	0	0	0	0	2014	
10551	168	256.29	66212	0	0	0	0	1	0	0	0	0	0	0	0	2014	
10546	168	251.97	63893	0	0	0	0	1	0	0	0	0	0	0	0	2014	
10587	168	253.02	64461	0	0	0	0	1	0	0	0	0	0	0	0	2014	
10587	168	256.84	66783	0	0	0	0	1	0	0	0	0	0	0	0	2014	
10669	168	268.61	74305	0	0	0	0	1	0	0	0	0	0	0	0	2014	
11237	168	295.32	92586	0	0	0	0	0	1	0	0	0	0	0	0	2014	JUN
10703	168	260.80	69553	0	0	0	0	0	1	0	0	0	0	0	0	2014	
11505	168	264.54	71837	0	0	0	0	0	1	0	0	0	0	0	0	2014	
11623	144	253.85	64923	0	0	0	0	0	1	0	0	0	0	0	0	2014	
10561	168	256.70	66808	0	0	0	0	0	0	1	0	0	0	0	0	2014	JUL

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	
10636	165	275.62	82271	0	0	0	0	0	0	1	0	0	0	0	0	2014	
10854	168	248.65	61851	0	0	0	0	0	0	1	0	0	0	0	0	2014	
10961	168	255.07	65867	0	0	0	0	0	0	1	0	0	0	0	0	2014	
10878	168	249.34	62253	0	0	0	0	0	0	0	1	0	0	0	0	2014	
10915	166	253.90	65981	0	0	0	0	0	0	0	1	0	0	0	0	2014	
10362	168	249.24	62190	0	0	0	0	0	0	0	1	0	0	0	0	2014	
11026	166	247.96	62469	0	0	0	0	0	0	0	1	0	0	0	0	2014	
10703	168	255.89	66014	0	0	0	0	0	0	0	1	0	0	0	0	2014	
11420	97	256.58	39197	0	0	0	0	0	0	0	0	1	0	0	0	2014	
0	0	0.00	0	0	0	0	0	0	0	0	0	1	0	0	0	2014	
0	0	0.00	0	0	0	0	0	0	0	0	0	1	0	0	0	2014	
0	0	0.00	0	0	0	0	0	0	0	0	0	1	0	0	0	2014	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2014	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2014	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2014	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2014	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2014	
*10266	68	179.28	17439	0	0	0	0	0	0	0	0	0	0	1	2	2014	
10825	168	254.73	65439	0	0	0	0	0	0	0	0	0	0	1	0	2014	
10700	168	255.58	66138	0	0	0	0	0	0	0	0	0	0	1	0	2014	
10800	168	246.17	60606	0	0	0	0	0	0	0	0	0	0	1	0	2014	
10612	168	288.99	90335	0	0	0	0	0	0	0	0	0	0	0	0	2014	
10414	168	274.17	79443	0	0	0	0	0	0	0	0	0	0	0	0	2014	
10735	168	245.76	60405	0	0	0	0	0	0	0	0	0	0	0	0	2014	
10749	168	244.04	59598	0	0	0	0	0	0	0	0	0	0	0	0	2014	
10938	121	253.98	56519	1	0	0	0	0	0	0	0	0	0	0	1	2015	JAN
10164	168	273.85	78353	1	0	0	0	0	0	0	0	0	0	0	0	2015	
9892	168	258.67	68748	1	0	0	0	0	0	0	0	0	0	0	0	2015	
10459	168	246.16	60681	1	0	0	0	0	0	0	0	0	0	0	0	2015	
10389	168	251.76	64318	0	1	0	0	0	0	0	0	0	0	0	0	2015	
10662	168	249.07	62491	0	1	0	0	0	0	0	0	0	0	0	0	2015	
10293	168	269.35	75510	0	1	0	0	0	0	0	0	0	0	0	0	2015	
10408	100	306.82	75512	0	1	0	0	0	0	0	0	0	0	0	1	2015	
10942	168	250.01	62755	0	0	1	0	0	0	0	0	0	0	0	0	2015	
10755	167	248.93	62257	0	0	1	0	0	0	0	0	0	0	0	0	2015	
10902	168	245.01	60090	0	0	1	0	0	0	0	0	0	0	0	0	2015	
10926	168	261.46	69897	0	0	1	0	0	0	0	0	0	0	0	0	2015	
10895	168	253.82	65244	0	0	1	0	0	0	0	0	0	0	0	0	2015	
10962	59	241.00	24655	0	0	0	1	0	0	0	0	0	0	0	0	2015	
10853	70	237.49	24915	0	0	0	1	0	0	0	0	0	0	0	1	2015	
11175	142	238.76	49831	0	0	0	1	0	0	0	0	0	0	0	0	2015	
*11732	20	152.35	3868	0	0	0	1	0	0	0	0	0	0	0	1	2015	
10451	168	291.70	89577	0	0	0	0	1	0	0	0	0	0	0	0	2015	
10250	168	317.21	107828	0	0	0	0	1	0	0	0	0	0	0	0	2015	
10401	168	318.08	108912	0	0	0	0	1	0	0	0	0	0	0	0	2015	
10703	168	262.51	70754	0	0	0	0	1	0	0	0	0	0	0	0	2015	
10741	168	252.79	64348	0	0	0	0	1	0	0	0	0	0	0	0	2015	
10782	168	286.85	86891	0	0	0	0	0	1	0	0	0	0	0	0	2015	
10776	165	315.11	109613	0	0	0	0	0	1	0	0	0	0	0	0	2015	
10608	168	336.38	122808	0	0	0	0	0	1	0	0	0	0	0	0	2015	
10833	144	300.44	97284	0	0	0	0	0	1	0	0	0	0	0	0	2015	
11116	168	278.23	81731	0	0	0	0	0	0	1	0	0	0	0	0	2015	JUL
10822	168	345.26	128535	0	0	0	0	0	0	1	0	0	0	0	0	2015	

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	
	10779	168	341.33	126788	0	0	0	0	0	0	1	0	0	0	0	0	2015	
	10633	168	345.46	129800	0	0	0	0	0	0	1	0	0	0	0	0	2015	
	10699	168	333.22	120976	0	0	0	0	0	0	0	1	0	0	0	0	2015	
	10743	168	330.73	119044	0	0	0	0	0	0	0	1	0	0	0	0	2015	
	10752	168	290.93	90426	0	0	0	0	0	0	0	1	0	0	0	0	2015	
	10850	165	306.02	100184	0	0	0	0	0	0	0	1	0	0	0	0	2015	
*	9608	88	277.31	46148	0	0	0	0	0	0	0	1	0	0	0	1	2015	
	10661	168	272.33	76499	0	0	0	0	0	0	0	0	1	0	0	0	2015	
	10285	168	273.32	79342	0	0	0	0	0	0	0	0	1	0	0	0	2015	
	10841	168	262.12	71026	0	0	0	0	0	0	0	0	1	0	0	0	2015	
	10608	168	256.48	67205	0	0	0	0	0	0	0	0	1	0	0	0	2015	
	10719	168	251.94	63867	0	0	0	0	0	0	0	0	0	1	0	0	2015	
	11293	168	250.49	62992	0	0	0	0	0	0	0	0	0	1	0	0	2015	
	10575	76	241.80	28184	0	0	0	0	0	0	0	0	0	1	0	0	2015	
	0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2015	
	0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2015	
	10761	129	240.70	52333	0	0	0	0	0	0	0	0	0	0	1	1	2015	
	11263	40	233.65	16029	0	0	0	0	0	0	0	0	0	0	1	0	2015	
	0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2015	
	0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2015	
	0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2015	
	0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2015	
	0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2015	
	0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2015	
	0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2016	JAN
	11155	103	254.30	43182	1	0	0	0	0	0	0	0	0	0	0	1	2016	
	10858	143	271.46	66947	1	0	0	0	0	0	0	0	0	0	0	0	2016	
	10646	164	308.09	104531	1	0	0	0	0	0	0	0	0	0	0	1	2016	
	10923	168	245.01	60076	0	1	0	0	0	0	0	0	0	0	0	0	2016	
	10722	165	261.27	70881	0	1	0	0	0	0	0	0	0	0	0	0	2016	
	10671	106	243.09	41988	0	1	0	0	0	0	0	0	0	0	0	0	2016	
	0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2016	
	0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2016	
	0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2016	
	0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2016	
*	0	2	1.00	0	0	0	1	0	0	0	0	0	0	0	0	1	2016	
*	13283	25	194.60	6618	0	0	1	0	0	0	0	0	0	0	0	1	2016	
	10727	168	250.29	62816	0	0	0	1	0	0	0	0	0	0	0	0	2016	
	11297	131	269.24	71569	0	0	0	1	0	0	0	0	0	0	0	1	2016	
*	12037	66	218.53	22829	0	0	0	1	0	0	0	0	0	0	0	1	2016	
	11125	168	255.12	67545	0	0	0	1	0	0	0	0	0	0	0	0	2016	
	11039	168	270.23	76955	0	0	0	0	1	0	0	0	0	0	0	0	2016	
	11137	164	258.70	71911	0	0	0	0	1	0	0	0	0	0	0	0	2016	
	11481	144	213.61	40027	0	0	0	0	1	0	0	0	0	0	0	0	2016	
	11156	110	238.62	43431	0	0	0	0	1	0	0	0	0	0	0	1	2016	
	11261	145	258.72	65241	0	0	0	0	1	0	0	0	0	0	0	1	2016	
	11057	168	276.80	86987	0	0	0	0	0	1	0	0	0	0	0	0	2016	
	10978	168	309.55	108372	0	0	0	0	0	1	0	0	0	0	0	0	2016	
	10618	168	291.18	97068	0	0	0	0	0	1	0	0	0	0	0	0	2016	
	10862	168	302.46	104990	0	0	0	0	0	1	0	0	0	0	0	0	2016	

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	
10684	168	213.32	50798	0	0	0	0	0	0	1	0	0	0	0	0	2013	JUL
10742	168	246.39	70953	0	0	0	0	0	0	1	0	0	0	0	0	2013	
10406	168	274.11	91323	0	0	0	0	0	0	1	0	0	0	0	0	2013	
10794	168	224.68	57652	0	0	0	0	0	0	1	0	0	0	0	0	2013	
10545	168	230.87	60607	0	0	0	0	0	0	0	1	0	0	0	0	2013	
10302	165	237.00	63706	0	0	0	0	0	0	0	1	0	0	0	0	2013	
10267	67	219.81	22610	0	0	0	0	0	0	0	1	0	0	0	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	1	0	0	0	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	1	0	0	0	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	1	0	0	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	1	0	0	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	1	0	0	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	1	0	0	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2013	
12019	71	187.15	15612	0	0	0	0	0	0	0	0	0	1	0	1	2013	
11367	168	214.33	48662	0	0	0	0	0	0	0	0	0	1	0	0	2013	
11168	168	227.60	57276	0	0	0	0	0	0	0	0	0	0	1	0	2013	
11048	168	444.51	201884	0	0	0	0	0	0	0	0	0	0	1	0	2013	
10240	28	228.21	12073	0	0	0	0	0	0	0	0	0	0	1	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2013	
10433	49	260.73	27157	0	0	0	0	0	0	0	0	0	0	0	1	2013	
10103	117	273.72	61122	0	0	0	0	0	0	0	0	0	0	0	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2013	
10408	158	332.86	121292	1	0	0	0	0	0	0	0	0	0	0	0	2014	JAN
10545	168	241.05	65261	1	0	0	0	0	0	0	0	0	0	0	0	2014	
10263	168	276.80	83094	1	0	0	0	0	0	0	0	0	0	0	0	2014	
10059	168	365.42	152137	1	0	0	0	0	0	0	0	0	0	0	0	2014	
10037	168	437.87	199018	0	1	0	0	0	0	0	0	0	0	0	0	2014	
10260	118	447.42	147817	0	1	0	0	0	0	0	0	0	0	0	0	2014	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2014	
10410	84	398.95	93858	0	1	0	0	0	0	0	0	0	0	0	2	2014	
10061	168	405.37	173053	0	0	1	0	0	0	0	0	0	0	0	0	2014	
9845	167	385.70	158668	0	0	1	0	0	0	0	0	0	0	0	0	2014	
10183	168	328.89	117495	0	0	1	0	0	0	0	0	0	0	0	0	2014	
10246	168	307.71	102543	0	0	1	0	0	0	0	0	0	0	0	0	2014	
10649	168	281.38	86018	0	0	1	0	0	0	0	0	0	0	0	0	2014	
11413	107	244.11	44167	0	0	0	1	0	0	0	0	0	0	0	0	2014	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2014	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2014	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2014	
11355	25	226.12	8591	0	0	0	0	1	0	0	0	0	0	0	1	2014	
10469	168	287.12	89736	0	0	0	0	1	0	0	0	0	0	0	0	2014	
10430	168	297.92	95263	0	0	0	0	1	0	0	0	0	0	0	0	2014	
10525	168	289.91	92358	0	0	0	0	1	0	0	0	0	0	0	0	2014	
10769	113	287.42	64936	0	0	0	0	1	0	0	0	0	0	0	1	2014	
10514	168	333.48	121774	0	0	0	0	0	1	0	0	0	0	0	0	2014	
10825	168	312.97	110138	0	0	0	0	0	1	0	0	0	0	0	0	2014	
10707	168	318.17	114970	0	0	0	0	0	1	0	0	0	0	0	0	2014	
10959	144	313.01	112148	0	0	0	0	0	1	0	0	0	0	0	0	2014	JUN
10563	168	318.29	116122	0	0	0	0	0	0	1	0	0	0	0	0	2014	

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	
10700	136	323.44	103470	0	0	0	0	0	0	1	0	0	0	0	1	2014	
10961	168	246.95	70000	0	0	0	0	0	0	1	0	0	0	0	0	2014	
10714	168	306.08	105461	0	0	0	0	0	0	1	0	0	0	0	0	2014	
10443	168	275.49	84998	0	0	0	0	0	0	0	1	0	0	0	0	2014	
10573	168	292.71	96302	0	0	0	0	0	0	0	1	0	0	0	0	2014	
10520	168	264.27	77270	0	0	0	0	0	0	0	1	0	0	0	0	2014	
10581	168	280.46	86451	0	0	0	0	0	0	0	1	0	0	0	0	2014	
10769	168	267.57	78704	0	0	0	0	0	0	0	1	0	0	0	0	2014	
10668	168	318.95	113814	0	0	0	0	0	0	0	0	1	0	0	0	2014	
10309	168	338.33	131388	0	0	0	0	0	0	0	0	1	0	0	0	2014	
10398	168	291.12	93572	0	0	0	0	0	0	0	0	1	0	0	0	2014	
10657	168	259.99	74327	0	0	0	0	0	0	0	0	1	0	0	0	2014	
11477	168	285.53	88874	0	0	0	0	0	0	0	0	0	1	0	0	2014	
10843	98	251.01	41025	0	0	0	0	0	0	0	0	0	1	0	0	2014	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2014	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2014	
* 9853	116	206.66	35758	0	0	0	0	0	0	0	0	0	1	0	1	2014	
10604	164	202.65	42018	0	0	0	0	0	0	0	0	0	0	1	0	2014	
10712	168	255.86	70339	0	0	0	0	0	0	0	0	0	0	1	0	2014	
10618	98	284.10	55258	0	0	0	0	0	0	0	0	0	0	1	0	2014	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2014	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2014	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2014	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2014	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2014	
11249	22	231.18	10155	1	0	0	0	0	0	0	0	0	0	0	1	2015	JAN
10133	89	202.39	25113	1	0	0	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2015	
* 3896	21	228.05	14239	0	0	0	1	0	0	0	0	0	0	0	1	2015	
11544	156	278.90	88100	0	0	0	1	0	0	0	0	0	0	0	0	2015	
*12665	123	230.80	45761	0	0	0	1	0	0	0	0	0	0	0	0	2015	
*13445	71	234.77	29060	0	0	0	1	0	0	0	0	0	0	0	1	2015	
*11859	168	291.73	94797	0	0	0	0	1	0	0	0	0	0	0	0	2015	
11569	167	313.34	113075	0	0	0	0	1	0	0	0	0	0	0	0	2015	
10416	168	332.51	120951	0	0	0	0	1	0	0	0	0	0	0	0	2015	
11390	168	238.67	62425	0	0	0	0	1	0	0	0	0	0	0	0	2015	
11434	168	227.94	56847	0	0	0	0	1	0	0	0	0	0	0	0	2015	
10758	168	263.98	78226	0	0	0	0	0	1	0	0	0	0	0	0	2015	
10084	164	287.55	94195	0	0	0	0	0	1	0	0	0	0	0	0	2015	
* 9371	116	309.97	80047	0	0	0	0	0	1	0	0	0	0	0	1	2015	
*12577	144	274.44	86810	0	0	0	0	0	1	0	0	0	0	0	0	2015	END OF JUN
9793	168	261.24	80467	0	0	0	0	0	0	1	0	0	0	0	0	2015	JUL
10352	168	317.83	119548	0	0	0	0	0	0	1	0	0	0	0	0	2015	

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	
10112	168	339.26	133439	0	0	0	0	0	0	1	0	0	0	0	0	2015	
10141	168	338.11	131612	0	0	0	0	0	0	1	0	0	0	0	0	2015	
10432	168	324.33	123023	0	0	0	0	0	0	0	1	0	0	0	0	2015	
10103	168	330.63	125684	0	0	0	0	0	0	0	1	0	0	0	0	2015	
10899	59	283.07	43513	0	0	0	0	0	0	0	1	0	0	0	1	2015	
10762	168	277.88	92924	0	0	0	0	0	0	0	1	0	0	0	0	2015	
10433	168	277.54	97730	0	0	0	0	0	0	0	1	0	0	0	0	2015	
9827	168	269.63	90941	0	0	0	0	0	0	0	0	1	0	0	0	2015	
9992	46	238.07	19783	0	0	0	0	0	0	0	0	1	0	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	1	0	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	1	0	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2015	
11497	163	179.39	39062	0	0	0	0	0	0	0	0	0	0	1	1	2015	
11665	155	193.32	44822	0	0	0	0	0	0	0	0	0	0	1	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2015	
*12668	43	160.28	8064	1	0	0	0	0	0	0	0	0	0	0	1	2016	JAN
11509	98	213.39	30163	1	0	0	0	0	0	0	0	0	0	0	1	2016	
11463	168	187.15	35979	1	0	0	0	0	0	0	0	0	0	0	0	2016	
11677	168	192.01	37868	1	0	0	0	0	0	0	0	0	0	0	0	2016	
11350	168	163.89	27218	0	1	0	0	0	0	0	0	0	0	0	0	2016	
11146	168	153.20	25037	0	1	0	0	0	0	0	0	0	0	0	0	2016	
10652	88	167.84	19332	0	1	0	0	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2016	
10951	157	212.63	51963	0	0	0	0	0	1	0	0	0	0	0	1	2016	
*12393	168	214.51	59016	0	0	0	0	0	1	0	0	0	0	0	0	2016	
*12475	168	239.18	71855	0	0	0	0	0	1	0	0	0	0	0	0	2016	

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	
11021	168	190.01	37492	0	0	0	0	0	0	1	0	0	0	0	0	2013	JUL
10718	168	231.46	61236	0	0	0	0	0	0	1	0	0	0	0	0	2013	
10343	168	261.21	83582	0	0	0	0	0	0	1	0	0	0	0	0	2013	
10706	168	222.51	56150	0	0	0	0	0	0	1	0	0	0	0	0	2013	
10721	168	223.99	55636	0	0	0	0	0	0	0	1	0	0	0	0	2013	
10633	168	234.47	61303	0	0	0	0	0	0	0	1	0	0	0	0	2013	
10866	168	191.67	39228	0	0	0	0	0	0	0	1	0	0	0	0	2013	
10775	168	218.18	52066	0	0	0	0	0	0	0	1	0	0	0	0	2013	
10388	168	252.58	72649	0	0	0	0	0	0	0	1	0	0	0	0	2013	
10590	71	250.96	33347	0	0	0	0	0	0	0	0	1	0	0	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	1	0	0	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	1	0	0	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	1	0	0	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	1	0	0	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	1	0	0	0	2013	
12512	27	182.07	7534	0	0	0	0	0	0	0	0	0	1	0	1	2013	
11444	47	243.40	18225	0	0	0	0	0	0	0	0	0	1	0	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2013	
10995	75	211.85	26660	0	0	0	0	0	0	0	0	0	0	1	1	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2013	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2013	
11262	97	266.55	43453	0	0	0	0	0	0	0	0	0	0	0	1	2013	
10705	168	259.64	73530	0	0	0	0	0	0	0	0	0	0	0	0	2013	
10285	168	312.37	108914	0	0	0	0	0	0	0	0	0	0	0	0	2013	
9891	168	378.27	152984	1	0	0	0	0	0	0	0	0	0	0	0	2014	JAN
10513	168	203.80	47268	1	0	0	0	0	0	0	0	0	0	0	0	2014	
10306	168	252.01	73158	1	0	0	0	0	0	0	0	0	0	0	0	2014	
9886	168	372.55	157573	1	0	0	0	0	0	0	0	0	0	0	0	2014	
9401	168	441.87	200970	0	1	0	0	0	0	0	0	0	0	0	0	2014	
9183	67	436.01	86369	0	1	0	0	0	0	0	0	0	0	0	0	2014	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2014	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2014	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2014	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2014	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2014	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2014	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2014	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2014	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2014	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2014	
*12439	34	253.59	28999	0	0	0	1	0	0	0	0	0	0	0	1	2014	
10007	55	291.09	34406	0	0	0	0	1	0	0	0	0	0	0	1	2014	
10653	168	278.36	84033	0	0	0	0	1	0	0	0	0	0	0	0	2014	
10426	168	289.81	89726	0	0	0	0	1	0	0	0	0	0	0	0	2014	
10450	166	291.66	94934	0	0	0	0	1	0	0	0	0	0	0	0	2014	
10577	168	287.35	90988	0	0	0	0	1	0	0	0	0	0	0	0	2014	
9915	168	332.07	119643	0	0	0	0	0	1	0	0	0	0	0	0	2014	
10635	168	310.18	108082	0	0	0	0	0	1	0	0	0	0	0	0	2014	
10633	164	312.87	111418	0	0	0	0	0	1	0	0	0	0	0	0	2014	
10245	144	312.67	111318	0	0	0	0	0	1	0	0	0	0	0	0	2014	JUN
10456	168	315.75	114209	0	0	0	0	0	0	1	0	0	0	0	0	2014	

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	
10446	168	324.14	120074	0	0	0	0	0	0	1	0	0	0	0	0	2014	
10635	168	239.73	64877	0	0	0	0	0	0	1	0	0	0	0	0	2014	
10368	168	318.35	114321	0	0	0	0	0	0	1	0	0	0	0	0	2014	
10518	168	286.69	92404	0	0	0	0	0	0	0	1	0	0	0	0	2014	JUL
10591	168	303.54	103671	0	0	0	0	0	0	0	1	0	0	0	0	2014	
10502	168	275.55	84407	0	0	0	0	0	0	0	1	0	0	0	0	2014	
10418	168	306.35	105599	0	0	0	0	0	0	0	1	0	0	0	0	2014	
10410	168	306.24	107509	0	0	0	0	0	0	0	1	0	0	0	0	2014	
10067	162	339.51	130020	0	0	0	0	0	0	0	0	1	0	0	0	2014	
10202	164	337.30	131513	0	0	0	0	0	0	0	0	1	0	0	0	2014	
9866	168	302.36	101055	0	0	0	0	0	0	0	0	1	0	0	0	2014	
10020	168	265.65	76887	0	0	0	0	0	0	0	0	1	0	0	0	2014	
10236	168	297.59	96732	0	0	0	0	0	0	0	0	0	1	0	0	2014	
10405	168	277.45	82436	0	0	0	0	0	0	0	0	0	1	0	0	2014	
10289	168	339.15	133746	0	0	0	0	0	0	0	0	0	1	0	0	2014	
10344	168	252.56	73887	0	0	0	0	0	0	0	0	0	1	0	0	2014	
10103	168	229.70	55363	0	0	0	0	0	0	0	0	0	1	0	0	2014	
10853	106	201.06	28392	0	0	0	0	0	0	0	0	0	0	1	0	2014	
9942	124	291.68	70935	0	0	0	0	0	0	0	0	0	0	1	1	2014	
10004	168	269.21	80973	0	0	0	0	0	0	0	0	0	0	1	0	2014	
10849	51	214.39	16346	0	0	0	0	0	0	0	0	0	0	1	0	2014	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2014	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2014	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2014	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2014	
*12565	49	238.80	20526	1	0	0	0	0	0	0	0	0	0	0	1	2015	JAN
*12530	95	211.53	30794	1	0	0	0	0	0	0	0	0	0	0	1	2015	
0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2015	
11075	154	210.81	46581	0	1	0	0	0	0	0	0	0	0	0	1	2015	
10951	161	223.34	56071	0	1	0	0	0	0	0	0	0	0	0	0	2015	
10608	168	184.39	34902	0	0	1	0	0	0	0	0	0	0	0	0	2015	
*10221	64	192.03	16326	0	0	1	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2015	
11741	28	231.39	13153	0	0	0	1	0	0	0	0	0	0	0	1	2015	
10146	166	269.87	82719	0	0	0	1	0	0	0	0	0	0	0	0	2015	
10989	168	224.85	53849	0	0	0	1	0	0	0	0	0	0	0	0	2015	
10612	24	254.38	10650	0	0	0	1	0	0	0	0	0	0	0	0	2015	
11470	21	305.10	15435	0	0	0	0	1	0	0	0	0	0	0	1	2015	
*12317	168	310.23	110771	0	0	0	0	1	0	0	0	0	0	0	0	2015	
10833	167	325.46	120017	0	0	0	0	1	0	0	0	0	0	0	0	2015	
*12486	168	235.88	61746	0	0	0	0	1	0	0	0	0	0	0	0	2015	
11398	168	231.23	59103	0	0	0	0	1	0	0	0	0	0	0	0	2015	
11434	168	274.93	85278	0	0	0	0	0	1	0	0	0	0	0	0	2015	
11152	168	293.64	100222	0	0	0	0	0	1	0	0	0	0	0	0	2015	
*11867	167	319.70	118064	0	0	0	0	0	1	0	0	0	0	0	0	2015	
*12580	133	267.75	86481	0	0	0	0	0	1	0	0	0	0	0	0	2015	END OF JUN
10668	168	255.46	77756	0	0	0	0	0	0	1	0	0	0	0	0	2015	JUL
10603	165	317.47	120332	0	0	0	0	0	0	1	0	0	0	0	0	2015	

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	
10246	168	344.95	137685	0	0	0	0	0	0	1	0	0	0	0	0	2015	
10077	165	386.71	159903	0	0	0	0	0	0	1	0	0	0	0	0	2015	
10191	168	401.17	167864	0	0	0	0	0	0	0	1	0	0	0	0	2015	
10089	168	414.90	175080	0	0	0	0	0	0	0	1	0	0	0	0	2015	
10129	168	395.92	158537	0	0	0	0	0	0	0	1	0	0	0	0	2015	
10264	168	389.34	154394	0	0	0	0	0	0	0	1	0	0	0	0	2015	
10068	168	370.46	140364	0	0	0	0	0	0	0	1	0	0	0	0	2015	
10164	167	382.12	147637	0	0	0	0	0	0	0	0	1	0	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	1	0	0	0	2015	
10514	87	299.00	58670	0	0	0	0	0	0	0	0	1	0	0	1	2015	
10591	168	280.43	96938	0	0	0	0	0	0	0	0	1	0	0	0	2015	
11061	168	210.22	49006	0	0	0	0	0	0	0	0	0	1	0	0	2015	
* 8154	71	223.04	23409	0	0	0	0	0	0	0	0	0	1	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	1	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2015	
11130	114	161.77	21470	0	0	0	0	0	0	0	0	0	0	1	1	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2015	
*13207	49	322.78	38512	0	0	0	0	0	0	0	0	0	0	0	1	2015	
11232	85	251.26	46386	0	0	0	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	1	0	0	0	0	0	0	0	0	0	0	0	2016	JAN
12641	105	155.97	19321	1	0	0	0	0	0	0	0	0	0	0	1	2016	
12259	168	154.75	25692	1	0	0	0	0	0	0	0	0	0	0	0	2016	
11407	168	256.81	76125	1	0	0	0	0	0	0	0	0	0	0	0	2016	
11072	168	216.86	57172	0	1	0	0	0	0	0	0	0	0	0	0	2016	
10472	168	245.95	70420	0	1	0	0	0	0	0	0	0	0	0	0	2016	
* 9846	135	196.21	38742	0	1	0	0	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	1	0	0	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	0	0	1	0	0	0	0	0	0	0	0	2016	
13054	65	177.20	16488	0	0	0	1	0	0	0	0	0	0	0	1	2016	
12157	168	147.01	22941	0	0	0	0	1	0	0	0	0	0	0	0	2016	
*13720	168	146.17	22195	0	0	0	0	1	0	0	0	0	0	0	0	2016	
13151	94	142.07	11722	0	0	0	0	1	0	0	0	0	0	0	0	2016	
0	0	0.00	0	0	0	0	0	1	0	0	0	0	0	0	0	2016	
12709	64	156.13	12719	0	0	0	0	1	0	0	0	0	0	0	1	2016	
12953	168	161.96	29770	0	0	0	0	0	1	0	0	0	0	0	0	2016	
11726	168	209.00	51646	0	0	0	0	0	1	0	0	0	0	0	0	2016	
11949	167	208.34	54897	0	0	0	0	0	1	0	0	0	0	0	0	2016	
11688	166	232.04	66655	0	0	0	0	0	1	0	0	0	0	0	0	2016	

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	
	6947	168	397.28	175915	0	0	0	0	0	0	1	0	0	0	0	0	2013	JUL
	6923	168	418.33	191927	0	0	0	0	0	0	1	0	0	0	0	0	2013	
	6898	168	433.57	201184	0	0	0	0	0	0	1	0	0	0	0	0	2013	
	6813	168	410.62	186512	0	0	0	0	0	0	1	0	0	0	0	0	2013	
	6817	168	454.03	216014	0	0	0	0	0	0	0	1	0	0	0	0	2013	
	6901	168	472.54	228175	0	0	0	0	0	0	0	1	0	0	0	0	2013	
	6836	168	420.30	184886	0	0	0	0	0	0	0	1	0	0	0	0	2013	
	6696	168	426.46	194176	0	0	0	0	0	0	0	1	0	0	0	0	2013	
	6804	168	446.96	212058	0	0	0	0	0	0	0	1	0	0	0	0	2013	
	6983	168	427.85	198541	0	0	0	0	0	0	0	0	1	0	0	0	2013	
	6862	168	462.03	224465	0	0	0	0	0	0	0	0	1	0	0	0	2013	
	6858	156	442.24	203552	0	0	0	0	0	0	0	0	1	0	0	0	2013	
	6700	168	469.39	225576	0	0	0	0	0	0	0	0	1	0	0	0	2013	
	6845	168	492.42	246869	0	0	0	0	0	0	0	0	0	1	0	0	2013	
	6895	168	499.82	252432	0	0	0	0	0	0	0	0	0	1	0	0	2013	
	6921	168	485.70	243549	0	0	0	0	0	0	0	0	0	1	0	0	2013	
	6743	165	500.28	258192	0	0	0	0	0	0	0	0	0	1	0	0	2013	
	6669	142	388.47	144315	0	0	0	0	0	0	0	0	0	1	0	1	2013	
	6818	168	471.30	225705	0	0	0	0	0	0	0	0	0	0	1	0	2013	
	6820	168	464.98	220893	0	0	0	0	0	0	0	0	0	0	1	0	2013	
	6851	168	461.58	217468	0	0	0	0	0	0	0	0	0	0	1	0	2013	
	7002	107	498.46	180479	0	0	0	0	0	0	0	0	0	0	1	0	2013	
	0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	2013	
	6880	157	450.15	210297	0	0	0	0	0	0	0	0	0	0	0	1	2013	
	6852	168	388.19	170191	0	0	0	0	0	0	0	0	0	0	0	0	2013	
	6935	168	433.58	195022	0	0	0	0	0	0	0	0	0	0	0	0	2013	
	6885	168	473.51	242603	1	0	0	0	0	0	0	0	0	0	0	0	2014	JAN
	6931	168	431.93	194851	1	0	0	0	0	0	0	0	0	0	0	0	2014	
	6952	168	353.20	137833	1	0	0	0	0	0	0	0	0	0	0	0	2014	
	6979	168	391.46	170984	1	0	0	0	0	0	0	0	0	0	0	0	2014	
	6981	168	337.20	131136	0	1	0	0	0	0	0	0	0	0	0	0	2014	
	7023	168	403.01	167236	0	1	0	0	0	0	0	0	0	0	0	0	2014	
	7081	168	374.50	146684	0	1	0	0	0	0	0	0	0	0	0	0	2014	
	7229	168	339.17	120133	0	1	0	0	0	0	0	0	0	0	0	0	2014	
	6637	168	406.18	182523	0	0	1	0	0	0	0	0	0	0	0	0	2014	
	6946	167	427.23	191231	0	0	1	0	0	0	0	0	0	0	0	0	2014	
	6910	168	380.68	162009	0	0	1	0	0	0	0	0	0	0	0	0	2014	
	6850	161	434.94	198904	0	0	1	0	0	0	0	0	0	0	0	0	2014	
	6928	168	425.10	191252	0	0	1	0	0	0	0	0	0	0	0	0	2014	
	6961	168	393.92	174512	0	0	0	1	0	0	0	0	0	0	0	0	2014	
	6879	168	436.68	205989	0	0	0	1	0	0	0	0	0	0	0	0	2014	
	6864	120	437.47	147299	0	0	0	1	0	0	0	0	0	0	0	0	2014	
	8210	17	162.71	5074	0	0	0	1	0	0	0	0	0	0	0	1	2014	
	6944	168	358.35	143701	0	0	0	0	1	0	0	0	0	0	0	0	2014	
	7003	168	354.30	148001	0	0	0	0	1	0	0	0	0	0	0	0	2014	
	6906	168	372.07	154350	0	0	0	0	1	0	0	0	0	0	0	0	2014	
	6882	168	429.35	202266	0	0	0	0	1	0	0	0	0	0	0	0	2014	
	6916	156	397.46	181763	0	0	0	0	1	0	0	0	0	0	0	0	2014	
	6959	168	439.10	208202	0	0	0	0	0	1	0	0	0	0	0	0	2014	JUN
	6940	168	406.61	183552	0	0	0	0	0	1	0	0	0	0	0	0	2014	
*	7923	168	415.14	193483	0	0	0	0	0	1	0	0	0	0	0	0	2014	
*	5768	144	419.26	195248	0	0	0	0	0	1	0	0	0	0	0	0	2014	
	6960	168	420.15	194871	0	0	0	0	0	0	1	0	0	0	0	0	2014	JUL

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	
6958	168	465.01	227581	0	0	0	0	0	0	1	0	0	0	0	0	2014	
6944	168	409.55	180885	0	0	0	0	0	0	1	0	0	0	0	0	2014	
6896	168	482.99	238117	0	0	0	0	0	0	1	0	0	0	0	0	2014	
6888	168	468.53	225781	0	0	0	0	0	0	0	1	0	0	0	0	2014	
7062	148	451.68	194049	0	0	0	0	0	0	0	1	0	0	0	0	2014	
6937	168	471.30	227700	0	0	0	0	0	0	0	1	0	0	0	0	2014	
6919	168	473.87	229774	0	0	0	0	0	0	0	1	0	0	0	0	2014	
6880	168	466.18	223512	0	0	0	0	0	0	0	1	0	0	0	0	2014	
6996	168	480.90	235845	0	0	0	0	0	0	0	0	1	0	0	0	2014	
6947	168	476.05	231782	0	0	0	0	0	0	0	0	1	0	0	0	2014	
6892	168	472.52	228638	0	0	0	0	0	0	0	0	1	0	0	0	2014	
6807	168	458.46	214796	0	0	0	0	0	0	0	0	1	0	0	0	2014	
6904	159	492.65	247620	0	0	0	0	0	0	0	0	0	1	0	0	2014	
6914	168	513.79	266408	0	0	0	0	0	0	0	0	0	1	0	0	2014	
6956	168	479.18	235480	0	0	0	0	0	0	0	0	0	1	0	0	2014	
6632	168	505.96	259897	0	0	0	0	0	0	0	0	0	1	0	0	2014	
6696	168	535.39	290471	0	0	0	0	0	0	0	0	0	1	0	0	2014	
6897	168	519.82	274633	0	0	0	0	0	0	0	0	0	0	1	0	2014	
6868	96	498.13	146626	0	0	0	0	0	0	0	0	0	0	1	0	2014	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2014	
7013	90	394.04	100199	0	0	0	0	0	0	0	0	0	0	1	1	2014	
6901	168	465.71	222761	0	0	0	0	0	0	0	0	0	0	0	0	2014	
6776	168	557.50	312323	0	0	0	0	0	0	0	0	0	0	0	0	2014	
6788	168	504.01	258176	0	0	0	0	0	0	0	0	0	0	0	0	2014	
6732	168	414.02	186353	0	0	0	0	0	0	0	0	0	0	0	0	2014	
6895	168	458.07	221039	1	0	0	0	0	0	0	0	0	0	0	0	2015	JAN
6892	168	510.02	267073	1	0	0	0	0	0	0	0	0	0	0	0	2015	
6806	168	486.45	244422	1	0	0	0	0	0	0	0	0	0	0	0	2015	
6900	168	469.45	227907	1	0	0	0	0	0	0	0	0	0	0	0	2015	
6893	168	501.78	261060	0	1	0	0	0	0	0	0	0	0	0	0	2015	
6880	155	468.53	222735	0	1	0	0	0	0	0	0	0	0	0	0	2015	
6851	168	505.13	263335	0	1	0	0	0	0	0	0	0	0	0	0	2015	
6831	168	458.88	235141	0	1	0	0	0	0	0	0	0	0	0	0	2015	
7092	168	421.52	195720	0	0	1	0	0	0	0	0	0	0	0	0	2015	
6985	167	426.67	201001	0	0	1	0	0	0	0	0	0	0	0	0	2015	
6647	166	464.40	222599	0	0	1	0	0	0	0	0	0	0	0	0	2015	
0	0	0.00	0	0	0	1	0	0	0	0	0	0	0	0	0	2015	
7301	117	445.56	146907	0	0	1	0	0	0	0	0	0	0	0	1	2015	
6942	168	444.36	202714	0	0	0	1	0	0	0	0	0	0	0	0	2015	
6952	168	460.02	221225	0	0	0	1	0	0	0	0	0	0	0	0	2015	
6919	149	462.46	226358	0	0	0	1	0	0	0	0	0	0	0	0	2015	
6758	156	452.56	219284	0	0	0	1	0	0	0	0	0	0	0	0	2015	
6890	162	479.56	239965	0	0	0	0	1	0	0	0	0	0	0	0	2015	
6912	168	488.24	243593	0	0	0	0	1	0	0	0	0	0	0	0	2015	
6937	125	481.78	188001	0	0	0	0	1	0	0	0	0	0	0	1	2015	
6876	137	434.56	205680	0	0	0	0	1	0	0	0	0	0	0	0	2015	
6971	127	433.98	205598	0	0	0	0	1	0	0	0	0	0	0	0	2015	
6980	106	472.05	167891	0	0	0	0	0	1	0	0	0	0	0	1	2015	
6930	162	471.19	231896	0	0	0	0	0	1	0	0	0	0	0	0	2015	
6866	168	480.51	237072	0	0	0	0	0	1	0	0	0	0	0	0	2015	
6925	129	468.42	229246	0	0	0	0	0	1	0	0	0	0	0	0	2015	
6959	168	431.82	201517	0	0	0	0	0	0	1	0	0	0	0	0	2015	JUL
6986	168	485.68	241335	0	0	0	0	0	0	1	0	0	0	0	0	2015	

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	
6967	168	418.64	191199	0	0	0	0	0	0	1	0	0	0	0	0	2015	
6886	168	458.16	218834	0	0	0	0	0	0	1	0	0	0	0	0	2015	
6906	160	472.86	230617	0	0	0	0	0	0	0	1	0	0	0	0	2015	
6988	168	480.10	235762	0	0	0	0	0	0	0	1	0	0	0	0	2015	
6952	168	474.35	231401	0	0	0	0	0	0	0	1	0	0	0	0	2015	
6947	168	470.18	227103	0	0	0	0	0	0	0	1	0	0	0	0	2015	
6775	168	422.46	195125	0	0	0	0	0	0	0	1	0	0	0	0	2015	
6985	161	469.52	232050	0	0	0	0	0	0	0	0	1	0	0	0	2015	
7060	148	438.91	211420	0	0	0	0	0	0	0	0	1	0	0	0	2015	
6908	162	451.41	217884	0	0	0	0	0	0	0	0	1	0	0	0	2015	
6795	156	487.11	245275	0	0	0	0	0	0	0	0	1	0	0	0	2015	
6822	168	460.46	224494	0	0	0	0	0	0	0	0	0	1	0	0	2015	
6847	168	500.87	255269	0	0	0	0	0	0	0	0	0	1	0	0	2015	
6853	168	494.39	249931	0	0	0	0	0	0	0	0	0	1	0	0	2015	
6681	168	521.24	273351	0	0	0	0	0	0	0	0	0	1	0	0	2015	
6720	168	522.97	275549	0	0	0	0	0	0	0	0	0	1	0	0	2015	
6889	71	512.65	113773	0	0	0	0	0	0	0	0	0	0	1	0	2015	
0	0	0.00	0	0	0	0	0	0	0	0	0	0	0	1	0	2015	
6909	141	453.48	185505	0	0	0	0	0	0	0	0	0	0	0	1	2015	
6979	94	433.07	113680	0	0	0	0	0	0	0	0	0	0	1	1	2015	
6868	163	486.61	245635	0	0	0	0	0	0	0	0	0	0	0	0	2015	DEC
6988	148	448.75	209220	0	0	0	0	0	0	0	0	0	0	0	0	2015	
6870	163	484.80	243967	0	0	0	0	0	0	0	0	0	0	0	0	2015	
6957	126	435.36	174088	0	0	0	0	0	0	0	0	0	0	0	1	2015	
6891	168	496.32	254350	1	0	0	0	0	0	0	0	0	0	0	0	2016	JAN
6859	153	519.68	277779	1	0	0	0	0	0	0	0	0	0	0	0	2016	
6894	130	515.44	229112	1	0	0	0	0	0	0	0	0	0	0	1	2016	
6991	168	485.60	246903	1	0	0	0	0	0	0	0	0	0	0	0	2016	
7228	110	403.59	155457	0	1	0	0	0	0	0	0	0	0	0	1	2016	
7054	168	500.17	257028	0	1	0	0	0	0	0	0	0	0	0	0	2016	
7072	165	473.68	231559	0	1	0	0	0	0	0	0	0	0	0	0	2016	
7054	161	417.71	192705	0	1	0	0	0	0	0	0	0	0	0	0	2016	
7105	168	498.90	257037	0	0	1	0	0	0	0	0	0	0	0	0	2016	
7041	168	535.48	288616	0	0	1	0	0	0	0	0	0	0	0	0	2016	
7045	167	529.81	282229	0	0	1	0	0	0	0	0	0	0	0	0	2016	
6972	168	548.54	302169	0	0	1	0	0	0	0	0	0	0	0	0	2016	
6874	168	503.14	258650	0	0	1	0	0	0	0	0	0	0	0	0	2016	
7059	168	500.83	258691	0	0	0	1	0	0	0	0	0	0	0	0	2016	
7111	168	509.75	262778	0	0	0	1	0	0	0	0	0	0	0	0	2016	
7077	168	526.90	279997	0	0	0	1	0	0	0	0	0	0	0	0	2016	
6925	168	498.74	252475	0	0	0	1	0	0	0	0	0	0	0	0	2016	
6978	24	506.42	37133	0	0	0	0	1	0	0	0	0	0	0	0	2016	
7263	92	467.24	132714	0	0	0	0	1	0	0	0	0	0	0	1	2016	
7145	131	458.56	189336	0	0	0	0	1	0	0	0	0	0	0	0	2016	
7291	146	469.58	236852	0	0	0	0	1	0	0	0	0	0	0	1	2016	
7106	168	496.28	249225	0	0	0	0	1	0	0	0	0	0	0	0	2016	
7200	168	490.28	243735	0	0	0	0	0	1	0	0	0	0	0	0	2016	
7159	168	498.89	251531	0	0	0	0	0	1	0	0	0	0	0	0	2016	
7083	168	470.33	227543	0	0	0	0	0	1	0	0	0	0	0	0	2016	
7102	168	472.74	229004	0	0	0	0	0	1	0	0	0	0	0	0	2016	

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 2017 - December 2017

		(1)	(2)	(3)	(4)	(5)
Unit	Month	Forecast AKW * 10^3	Forecast LSRF * 10^6	Forecast Monthly ANOHR	Forecast AKWH * 10^3 Generation	Weighted ANOHR Target
SCHERER 3	Jan '17	423.3	199,557	10,981	310,312	
	Feb '17	444.7	218,167	11,071	291,690	
	Mar '17	482.9	253,300	10,643	349,154	
	Apr '17	456.8	229,030	10,886	302,853	
	May '17	469.4	240,604	11,071	277,865	
	Jun '17	493.5	263,483	10,797	349,923	
	Jul '17	511.3	281,009	10,759	374,756	
	Aug '17	510.9	280,609	10,759	369,910	
	Sep '17	459.0	231,032	10,880	10,558	
	Oct '17	0.0	0	-	0	
	Nov '17	402.5	182,206	11,047	236,658	
	Dec '17	441.3	215,159	10,928	321,276	10,878
CRIST 7	Jan '17	292.3	88,765	10,322	139,411	
	Feb '17	308.2	101,804	10,341	133,435	
	Mar '17	318.7	110,880	10,465	141,837	
	Apr '17	317.5	109,824	10,738	67,942	
	May '17	325.1	116,592	10,447	199,258	
	Jun '17	362.7	152,922	10,669	228,878	
	Jul '17	382.0	173,408	10,492	281,534	
	Aug '17	376.0	166,906	10,503	271,117	
	Sep '17	365.4	155,713	10,348	246,645	
	Oct '17	316.9	109,298	10,470	213,932	
	Nov '17	312.0	105,046	10,484	169,729	
	Dec '17	347.8	137,959	10,389	89,033	10,470

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 2017 - December 2017

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 '17	222.0	50,016	10,619	79,712	
	Feb '17	250.5	63,700	10,521	84,421	
	Mar '17	233.2	55,198	10,577	113,545	
	Apr '17	263.2	70,325	11,472	13,947	
	May '17	259.8	68,520	10,922	81,846	
	Jun '17	286.2	83,152	10,686	167,137	
	Jul '17	336.3	114,785	10,327	241,808	
	Aug '17	329.1	109,928	10,339	241,861	
	Sep '17	300.9	91,909	10,394	211,213	
	Oct '17	251.8	64,363	11,245	38,778	
	Nov '17	239.0	57,981	10,977	66,437	
	Dec '17	299.8	91,239	10,396	34,477	10,539
DANIEL 2	Jan '17	228.3	52,939	11,012	85,381	
	Feb '17	257.3	67,022	10,324	69,732	
	Mar '17	231.6	54,459	10,176	28,481	
	Apr '17	0.0	0	-	0	
	May '17	247.6	62,129	10,815	10,399	
	Jun '17	287.3	83,318	10,861	155,726	
	Jul '17	334.6	112,580	10,211	244,952	
	Aug '17	327.7	108,039	10,247	239,840	
	Sep '17	292.1	86,088	10,461	157,708	
	Oct '17	265.9	71,514	10,655	70,185	
	Nov '17	228.4	52,985	10,546	66,464	
	Dec '17	226.8	52,255	11,029	10,660	10,468
SMITH 3	Jan '17	504.4	248,708	6,892	301,153	
	Feb '17	514.9	257,484	6,978	344,485	
	Mar '17	514.6	257,231	6,944	380,299	
	Apr '17	529.2	269,666	6,958	265,635	
	May '17	476.4	226,010	6,990	341,100	
	Jun '17	472.1	222,615	7,013	332,365	
	Jul '17	492.2	238,693	6,893	364,226	
	Aug '17	486.7	234,241	6,893	360,184	
	Sep '17	482.8	231,108	6,894	345,664	
	Oct '17	483.2	231,429	6,805	357,569	
	Nov '17	485.9	233,597	6,893	348,367	
	Dec '17	488.8	235,936	6,893	256,638	6,920

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 2017 - December 2017

Unit	Target Heat Rate BTU/KWH (0 Points)	Minimum Attainable Heat Rate (+ 10 Points)	Maximum Attainable Heat Rate (- 10 Points)
SCHERER 3	10,878	10,552	11,204
CRIST 7	10,470	10,156	10,784
DANIEL 1	10,539	10,223	10,855
DANIEL 2	10,468	10,154	10,782
SMITH 3	6,920	6,712	7,128

II. DETERMINATION OF EQUIVALENT AVAILABILITY TARGETS

Calculation of
Target Equivalent Availabilities
for January 2017 - December 2017

Unit	5 Year Historical Average of Equivalent Unplanned Outage Rate, EUOR *	Planned Outage Hours for Jan '17 - Dec '17	Reserve Shutdown Hours for Jan '17 - Dec '17	Target Equivalent Availability **
Scherer 3	0.0394	1,560	61	79.0
Crist 7	0.0521	0	2,002	96.0
Daniel 1	0.1009	336	3,094	90.5
Daniel 2	0.0752	1,824	2,673	75.7
Smith 3	0.0201	432	54	93.1

* For Period July 2011 through June 2016.

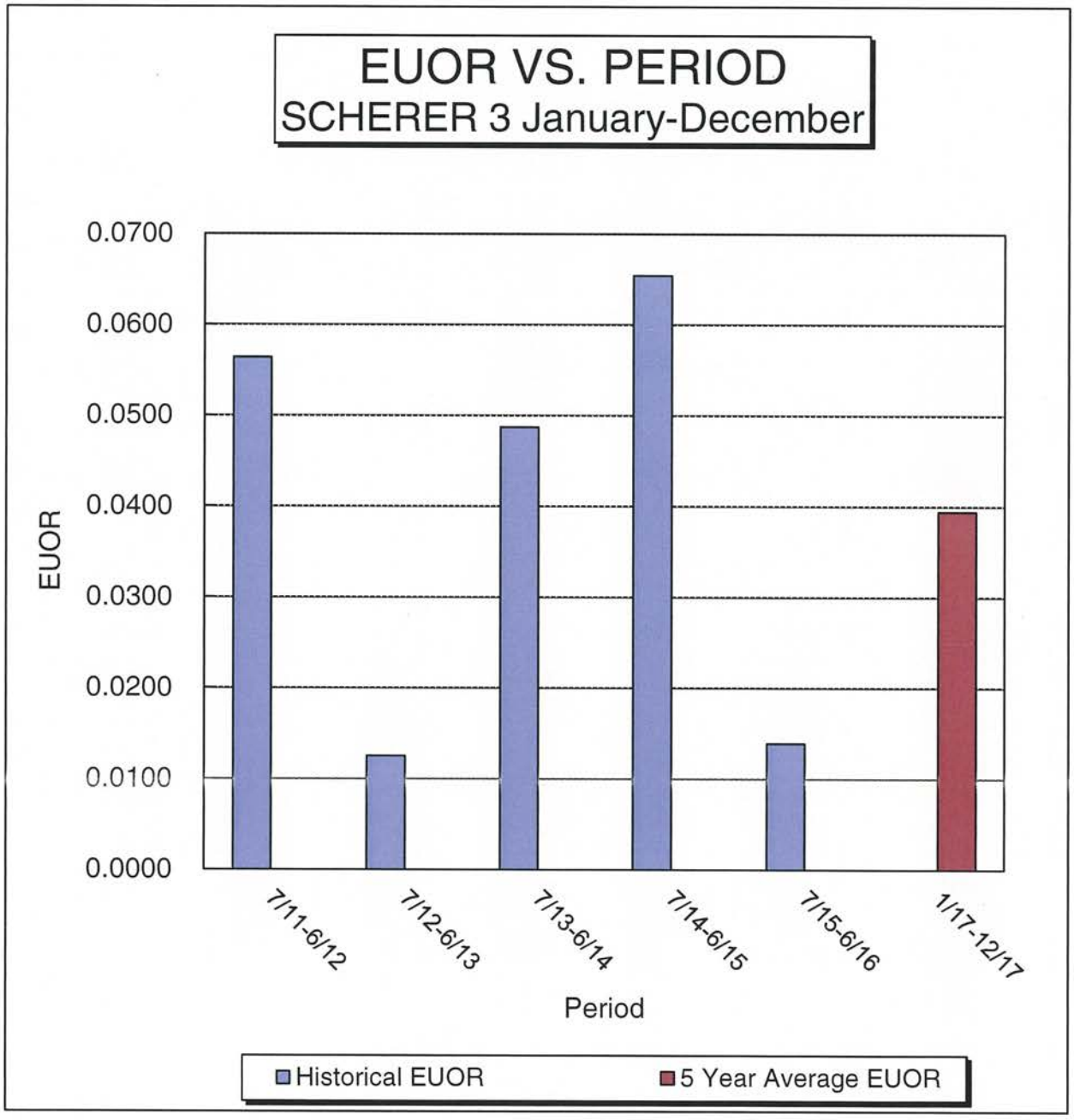
** EA = [1 - (POH + EUOR * (PH - POH - RSH)) / PH] * 100

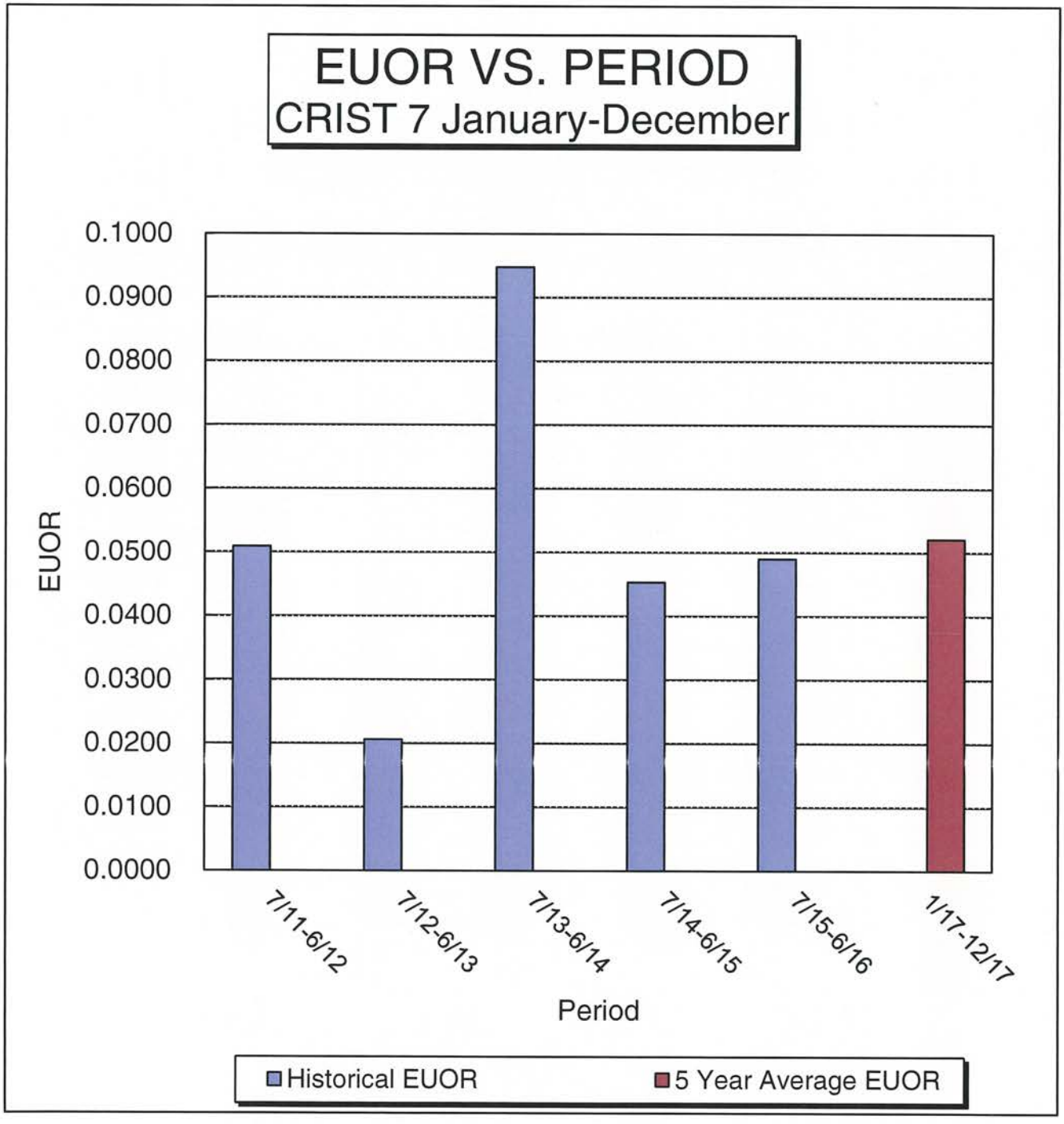
Calculation of Maximum and Minimum
Attainable Equivalent Availabilities
for January 2017 - December 2017

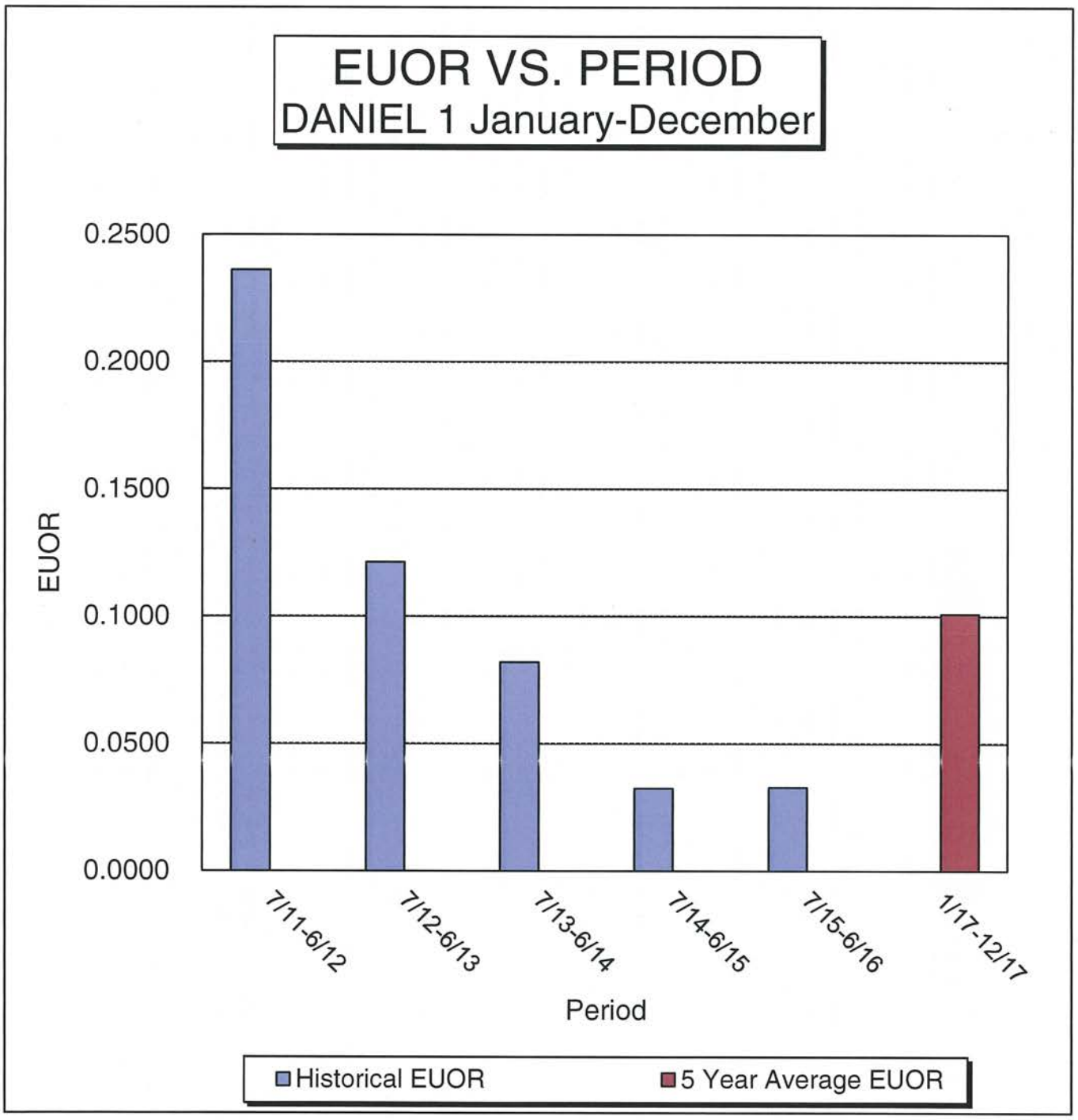
Unit	5 Year Historical Average of Equivalent Unplanned Outage Rate, EUOR (TARGET EUOR)	Minimum Attainable EUOR 70% of Target EUOR	Maximum Attainable Equivalent Availability	Maximum Attainable EUOR 145% of Target EUOR	Minimum Attainable Equivalent Availability
Scherer 3	0.0394	0.0276	79.9	0.0571	77.5
Crist 7	0.0521	0.0365	97.2	0.0755	94.2
Daniel 1	0.1009	0.0706	91.9	0.1463	87.3
Daniel 2	0.0752	0.0526	76.6	0.1090	73.9
Smith 3	0.0201	0.0141	93.7	0.0291	92.3

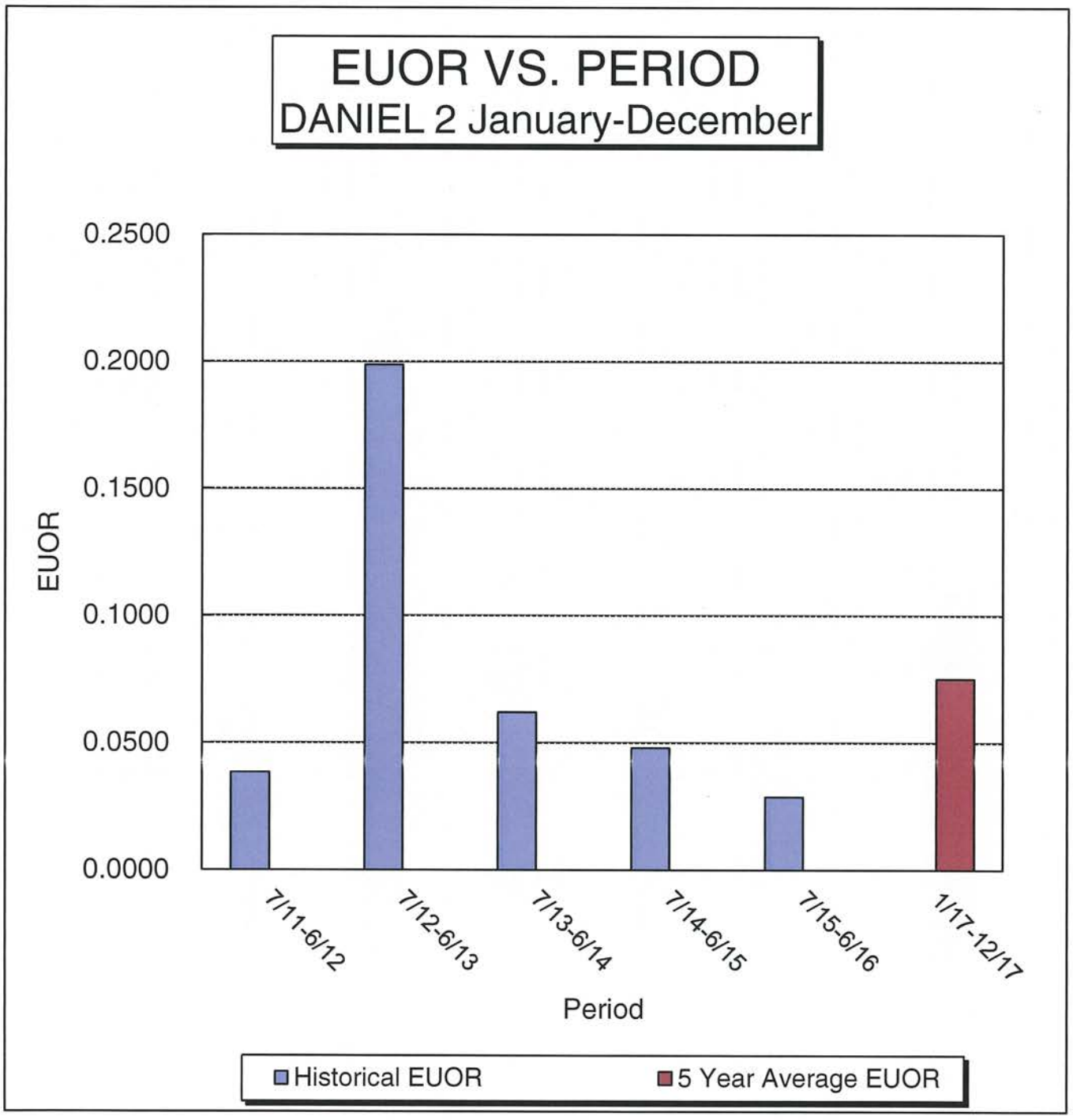
Summary of Target, Maximum, and Minimum
Equivalent Availabilities
for January 2017 - December 2017

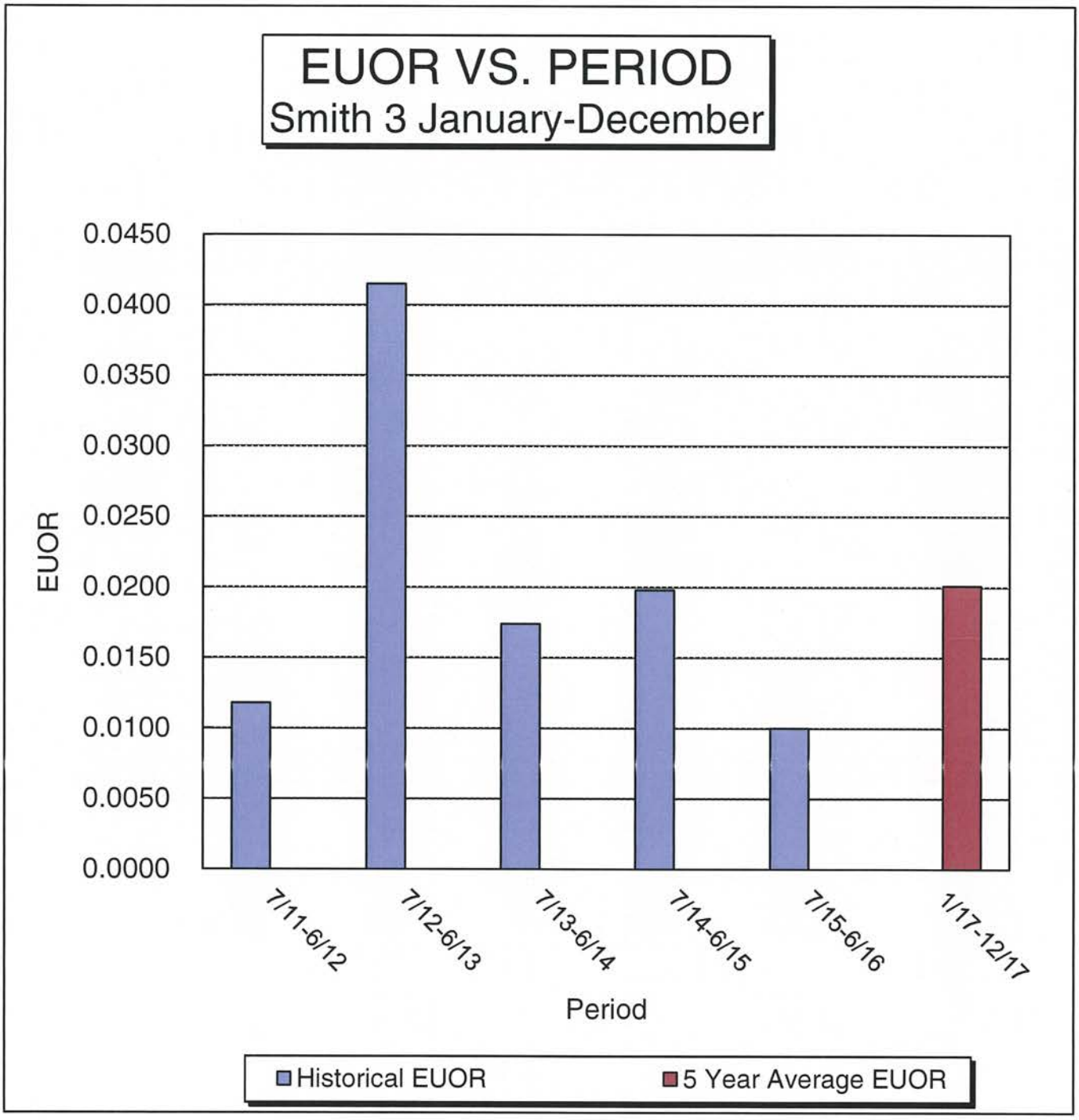
Unit	Target Equivalent Availability (0 Points)	Maximum Attainable Equivalent Availability (+10 Points)	Minimum Attainable Equivalent Availability (-10 Points)
Scherer 3	79.0	79.9	77.5
Crist 7	96.0	97.2	94.2
Daniel 1	90.5	91.9	87.3
Daniel 2	75.7	76.6	73.9
Smith 3	93.1	93.7	92.3


EUOR VS. PERIOD
SCHERER 3 January-December
0.0700
0.0600
0.0500
0.0400
0.0300
0.0200
0.0100
0.0000
EUOR
7/11-6/12
7/12-6/13
7/13-6/14
7/14-6/15
7/15-6/16
1/17-12/17
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
CRIST 7 January-December
0.1000
0.0900
0.0800
0.0700
0.0600
0.0500
0.0400
0.0300
0.0200
0.0100
0.0000
EUOR
7/11-6/12
7/12-6/13
7/13-6/14
7/14-6/15
7/15-6/16
1/17-12/17
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
DANIEL 1 January-December
0.2500
0.2000
0.1500
0.1000
0.0500
0.0000
EUOR
7/11-6/12
7/12-6/13
7/13-6/14
7/14-6/15
7/15-6/16
1/17-12/17
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
7/11-6/12
7/12-6/13
7/13-6/14
7/14-6/15
7/15-6/16
1/17-12/17
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
Smith 3 January-December
0.0450
0.0400
0.0350
0.0300
0.0250
0.0200
0.0150
0.0100
0.0050
0.0000
EUOR
7/11-6/12
7/12-6/13
7/13-6/14
7/14-6/15
7/15-6/16
1/17-12/17
Period
Historical EUOR
5 Year Average EUOR

III. GPIF MINIMUM FILING REQUIREMENTS FOR THE PERIOD JANUARY 2017 - DECEMBER 2017

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Generating Performance Incentive Factor

Estimated Reward/Penalty Table

Gulf Power Company

Period of: January 2017 - December 2017

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	6672	3336
+ 9	6005	3002
+ 8	5338	2669
+ 7	4670	2335
+ 6	4003	2002
+ 5	3336	1668
+ 4	2669	1334
+ 3	2002	1001
+ 2	1334	667
+ 1	667	334
0	0	0
- 1	-649	-334
- 2	-1299	-667
- 3	-1948	-1001
- 4	-2598	-1334
- 5	-3247	-1668
- 6	-3896	-2002
- 7	-4546	-2335
- 8	-5195	-2669
- 9	-5845	-3002
- 10	-6494	-3336
	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 2017 - December 2017

Line 1	Beginning of Period Balance of Common Equity	$1,365,482,686
	End of Month Balance of Common Equity:	
Line 2	Month of Jan '16	$1,353,038,140
Line 3	Month of Feb '16	$1,358,713,221
Line 4	Month of Mar '16	$1,362,458,671
Line 5	Month of Apr '16	$1,332,750,825
Line 6	Month of May '16	$1,342,362,829
Line 7	Month of Jun '16	$1,358,614,370
Line 8	Month of Jul '16	$1,344,973,877
Line 9	Month of Aug '16	$1,361,358,121
Line 10	Month of Sep '16	$1,376,270,438
Line 11	Month of Oct '16	$1,351,665,074
Line 12	Month of Nov '16	$1,353,268,957
Line 13	Month of Dec '16	$1,375,018,655
Line 14	Average Common Equity for the Period (sum of line 1 through line 13 divided by 13)	$1,356,613,528
Line 15	25 Basis Points	0.0025
Line 16	Revenue Expansion Factor	61.1928%
Line 17	Maximum Allowed Incentive Dollars (line 14 multiplied by line 15 divided by line 16 multiplied by 1.0)	$5,542,374
Line 18	Jurisdictional Sales (KWH)	11,022,524,913
Line 19	Total Territorial Sales (KWH)	11,362,016,616
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	97.0120%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 multiplied by line 20)	$5,376,770
Line 22	Incentive Cap (50% of Projected Fuel Savings at 10 GPIF point level from sheet 6.389.4)	$3,336,000
Line 23	Maximum Allowed GPIF Reward (at 10 GPIF Pt. leve (The lesser of Line 21 and Line 22)	$3,336,000

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GPIF Unit Performance Summary

Gulf Power Company

Period of: January 2017 - December 2017

Plant & Unit	Weighting Factor %	EAF Target %	EAF Range Max %	EAF Range Min %	Max Fuel Savings ($000)	Max Fuel Loss ($000)
Scherer 3	0.3%	79.0	79.9	77.5	$22	$20
Crist 7	0.1%	96.0	97.2	94.2	$10	$5
Daniel 1	0.0%	90.5	91.9	87.3	$1	$6
Daniel 2	0.1%	75.7	76.6	73.9	$5	$4
Smith 3	0.7%	93.1	93.7	92.3	$50	$55

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	26.2%	10,878	54.4	10,552	11,204	$1,750	($1,750)
Crist 7	24.8%	10,470	71.6	10,156	10,784	$1,655	($1,655)
Daniel 1	7.0%	10,539	55.7	10,223	10,855	$467	($467)
Daniel 2	5.8%	10,468	56.5	10,154	10,782	$386	($386)
Smith 3	34.9%	6,920	87.2	6,712	7,128	$2,326	($2,326)

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Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Availability

Gulf Power Company

Period of: January 2017 - December 2017

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Target			Actual Performance 1st Prior Period Jul '015 - Jun '016			Actual Performance 2nd Prior Period Jul '014 - Jun '015		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Scherer 3	0.3%	25.0%	0.1781	0.0318	0.0394	0.0000	0.0120	0.0139	0.1589	0.0550	0.0654
Crist 7	0.1%	11.4%	0.0000	0.0404	0.0521	0.1133	0.0322	0.0490	0.1938	0.0363	0.0453
Daniel 1	0.0%	1.1%	0.0384	0.0562	0.1009	0.0124	0.0135	0.0328	0.2231	0.0185	0.0324
Daniel 2	0.1%	5.7%	0.2082	0.0350	0.0752	0.0102	0.0153	0.0287	0.0495	0.0335	0.0480
Smith 3	0.7%	56.8%	0.0493	0.0193	0.0201	0.0583	0.0090	0.0100	0.0614	0.0182	0.0198
Weighted GPIF System Average:			0.0848	0.0261	0.0326	0.0467	0.0128	0.0167	0.1020	0.0303	0.0358

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Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Availability

Gulf Power Company

Period of: January 2017 - December 2017

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Actual Performance 3rd Prior Period Jul '013 - Jun '014			Actual Performance 4th Prior Period Jul '012 - Jun '013			Actual Performance 5th Prior Period Jul '011 - Jun '012		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Scherer 3	0.3%	25.0%	0.0000	0.0484	0.0487	0.1541	0.0102	0.0125	0.0000	0.0541	0.0564
Crist 7	0.1%	11.4%	0.0000	0.0927	0.0948	0.2632	0.0133	0.0206	0.0000	0.0470	0.0509
Daniel 1	0.0%	1.1%	0.0482	0.0519	0.0820	0.0000	0.0553	0.1213	0.1378	0.0872	0.2362
Daniel 2	0.1%	5.7%	0.2175	0.0338	0.0620	0.1514	0.0681	0.1988	0.2123	0.0201	0.0384
Smith 3	0.7%	56.8%	0.0447	0.0165	0.0174	0.0654	0.0386	0.0415	0.0390	0.0113	0.0118
Weighted GPIF System Average:			0.0383	0.0345	0.0373	0.1142	0.0305	0.0417	0.0358	0.0274	0.0315

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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 2017 - December 2017

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Heat Rate Target	1st Prior Period Heat Rate Jul '015 - Jun '016	2nd Prior Period Heat Rate Jul '014 - Jun '015	3rd Prior Period Heat Rate Jul '013 - Jun '014
Scherer 3	26.2%	26.6%	10,878	10,833	10,970	10,872
Crist 7	24.8%	25.1%	10,470	10,663	10,471	10,403
Daniel 1	7.0%	7.1%	10,539	10,549	10,624	10,504
Daniel 2	5.8%	5.9%	10,468	10,467	10,654	10,253
Smith 3	34.9%	35.3%	6,920	6,979	6,893	6,877
Weighted GPIF System Average:			9,329	9,387	9,361	9,280

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Example Calculation of Prior Season

Average Net Operating Heat Rate

Adjusted to Target Basis

Crist 7 Jul '014 - Jun '015

	Jul Jan	Aug Feb	Sep Mar	Oct Apr	Nov May	Dec Jun
1. Target Heat Rate*	10492.0 10322.0	10503.0 10341.0	10348.0 10465.0	10470.0 10738.0	10484.0 10447.0	10389.0 10669.0
2. Target Heat Rate at Actual Conditions**	10942.0 10428.0	10971.0 10465.0	10666.0 10706.0	0.0 11140.0	10742.0 10547.0	10658.0 10882.0
3. Adjustments to Actual Heat Rate (1-2)	-450.0 -106.0	-468.0 -124.0	-318.0 -241.0	10470.0 -402.0	-258.0 -100.0	-269.0 -213.0
4. Actual Heat Rate for Prior Period	10746.0 10328.0	10770.0 10512.0	11308.0 10866.0	0.0 11050.0	10727.0 10444.0	10619.0 10753.0
5. Adjusted actual Heat Rate (4+3)	10296.0 10222.0	10302.0 10388.0	10990.0 10625.0	10470.0 10648.0	10469.0 10344.0	10350.0 10540.0
6. Forecast Net MWH Generation*	281533.8 139410.5	271117.4 133435.1	246645.1 141836.9	213931.7 67941.7	169728.5 199258.0	89032.9 228878.4

7. Adjusted Actual Heat Rate for Jul '014 - Jun '015 = (Σ ((5) * (6))) / (Σ (6)) 10,471

* For the January 2017 - December 2017 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 2017 - December 2017

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	$354,337	$354,315	$22	0.3%
Scherer 3	ANOHR-3	$354,337	$352,587	$1,750	26.2%
Crist 7	EA-4	$354,337	$354,327	$10	0.1%
Crist 7	ANOHR-4	$354,337	$352,682	$1,655	24.8%
Daniel 1	EA-5	$354,337	$354,336	$1	0.0%
Daniel 1	ANOHR-5	$354,337	$353,870	$467	7.0%
Daniel 2	EA-6	$354,337	$354,332	$5	0.1%
Daniel 2	ANOHR-6	$354,337	$353,951	$386	5.8%
Smith 3	EA-7	$354,337	$354,287	$50	0.7%
Smith 3	ANOHR-7	$354,337	$352,011	$2,326	34.9%

(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 2017 - December 2017

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	22	79.90	+ 10	1,750	10,552
+ 9	20	79.81	+ 9	1,575	10,577
+ 8	18	79.72	+ 8	1,400	10,602
+ 7	15	79.63	+ 7	1,225	10,627
+ 6	13	79.54	+ 6	1,050	10,652
+ 5	11	79.45	+ 5	875	10,678
+ 4	9	79.36	+ 4	700	10,703
+ 3	7	79.27	+ 3	525	10,728
+ 2	4	79.18	+ 2	350	10,753
+ 1	2	79.09	+ 1	175	10,778
				0	10,803
0	0	79.00	0	0	10,878
				0	10,953
- 1	2	78.85	- 1	(175)	10,978
- 2	4	78.70	- 2	(350)	11,003
- 3	6	78.55	- 3	(525)	11,028
- 4	8	78.40	- 4	(700)	11,053
- 5	10	78.25	- 5	(875)	11,079
- 6	12	78.10	- 6	(1,050)	11,104
- 7	14	77.95	- 7	(1,225)	11,129
- 8	16	77.80	- 8	(1,400)	11,154
- 9	18	77.65	- 9	(1,575)	11,179
- 10	20	77.50	- 10	(1,750)	11,204
Weighting Factor:		0.003	Weighting Factor:		0.262

Issued by: S. W. Connally, Jr.

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2017 - December 2017

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	10	97.20	+ 10	1,655	10,156
+ 9	9	97.08	+ 9	1,490	10,180
+ 8	8	96.96	+ 8	1,324	10,204
+ 7	7	96.84	+ 7	1,159	10,228
+ 6	6	96.72	+ 6	993	10,252
+ 5	5	96.60	+ 5	828	10,276
+ 4	4	96.48	+ 4	662	10,299
+ 3	3	96.36	+ 3	497	10,323
+ 2	2	96.24	+ 2	331	10,347
+ 1	1	96.12	+ 1	166	10,371
				0	10,395
0	0	96.00	0	0	10,470
				0	10,545
- 1	1	95.82	- 1	(166)	10,569
- 2	1	95.64	- 2	(331)	10,593
- 3	2	95.46	- 3	(497)	10,617
- 4	2	95.28	- 4	(662)	10,641
- 5	3	95.10	- 5	(828)	10,665
- 6	3	94.92	- 6	(993)	10,688
- 7	4	94.74	- 7	(1,159)	10,712
- 8	4	94.56	- 8	(1,324)	10,736
- 9	5	94.38	- 9	(1,490)	10,760
- 10	5	94.20	- 10	(1,655)	10,784
Weighting Factor:		0.001	Weighting Factor:		0.248

Issued by: S. W. Connally, Jr.

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2017 - December 2017

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	91.90	+ 10	467	10,223
+ 9	1	91.71	+ 9	420	10,247
+ 8	1	91.52	+ 8	374	10,271
+ 7	1	91.33	+ 7	327	10,295
+ 6	1	91.14	+ 6	280	10,319
+ 5	1	90.95	+ 5	234	10,344
+ 4	0	90.76	+ 4	187	10,368
+ 3	0	90.57	+ 3	140	10,392
+ 2	0	90.38	+ 2	93	10,416
+ 1	0	90.19	+ 1	47	10,440
				0	10,464
0	0	90.00	0	0	10,539
				0	10,614
- 1	1	89.73	- 1	(47)	10,638
- 2	1	89.46	- 2	(93)	10,662
- 3	2	89.19	- 3	(140)	10,686
- 4	2	88.92	- 4	(187)	10,710
- 5	3	88.65	- 5	(234)	10,735
- 6	4	88.38	- 6	(280)	10,759
- 7	4	88.11	- 7	(327)	10,783
- 8	5	87.84	- 8	(374)	10,807
- 9	5	87.57	- 9	(420)	10,831
- 10	6	87.30	- 10	(467)	10,855
Weighting Factor:		0.000	Weighting Factor:		0.070

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2017 - December 2017

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	5	76.60	+ 10	386	10,154
+ 9	5	76.49	+ 9	347	10,178
+ 8	4	76.38	+ 8	309	10,202
+ 7	4	76.27	+ 7	270	10,226
+ 6	3	76.16	+ 6	232	10,250
+ 5	3	76.05	+ 5	193	10,274
+ 4	2	75.94	+ 4	154	10,297
+ 3	2	75.83	+ 3	116	10,321
+ 2	1	75.72	+ 2	77	10,345
+ 1	1	75.61	+ 1	39	10,369
				0	10,393
0	0	75.50	0	0	10,468
				0	10,543
- 1	0	75.34	- 1	(39)	10,567
- 2	1	75.18	- 2	(77)	10,591
- 3	1	75.02	- 3	(116)	10,615
- 4	2	74.86	- 4	(154)	10,639
- 5	2	74.70	- 5	(193)	10,663
- 6	2	74.54	- 6	(232)	10,686
- 7	3	74.38	- 7	(270)	10,710
- 8	3	74.22	- 8	(309)	10,734
- 9	4	74.06	- 9	(347)	10,758
- 10	4	73.90	- 10	(386)	10,782
Weighting Factor:		0.001	Weighting Factor:		0.058

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2017 - December 2017

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	50	93.70	+ 10	2,326	6,712
+ 9	45	93.65	+ 9	2,093	6,725
+ 8	40	93.60	+ 8	1,861	6,739
+ 7	35	93.55	+ 7	1,628	6,752
+ 6	30	93.50	+ 6	1,396	6,765
+ 5	25	93.45	+ 5	1,163	6,779
+ 4	20	93.40	+ 4	930	6,792
+ 3	15	93.35	+ 3	698	6,805
+ 2	10	93.30	+ 2	465	6,818
+ 1	5	93.25	+ 1	233	6,832
				0	6,845
0	0	93.20	0	0	6,920
				0	6,995
- 1	6	93.11	- 1	(233)	7,008
- 2	11	93.02	- 2	(465)	7,022
- 3	17	92.93	- 3	(698)	7,035
- 4	22	92.84	- 4	(930)	7,048
- 5	28	92.75	- 5	(1,163)	7,062
- 6	33	92.66	- 6	(1,396)	7,075
- 7	39	92.57	- 7	(1,628)	7,088
- 8	44	92.48	- 8	(1,861)	7,101
- 9	50	92.39	- 9	(2,093)	7,115
- 10	55	92.30	- 10	(2,326)	7,128
Weighting Factor:		0.007	Weighting Factor:		0.349

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ESTIMATED UNIT PERFORMANCE DATA

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2017 - December 2017

	SCHERER 3	Jan '17	Feb '17	Mar '17	Apr '17	May '17	Jun '17	
1.	EAF (%)	98.5	98.5	98.5	92.2	83.1	97.9	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	1.5	1.5	1.5	7.8	16.9	2.1	
4.	EUOR (%)	1.5	1.5	1.5	7.8	17.5	2.1	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	733.0	656.0	723.0	663.0	592.0	709.0	
7.	RSH	0.0	6.0	9.0	1.0	26.0	0.0	
8.	UH	11.0	10.0	11.0	56.0	126.0	11.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	11.0	10.0	11.0	10.0	9.0	15.0	
11.	MOH & EMOH	0.0	0.0	0.0	46.0	117.0	0.0	
12.	Oper MBtu	3407532	3229304	3716042	3296860	3076241	3778116	
13.	Net Gen (MWH)	310311.6	291690.4	349153.6	302853.2	277864.8	349922.8	
14.	ANOHR (Btu/KWH)	10981.0	11071.0	10643.0	10886.0	11071.0	10797.0	
15.	NOF %	49.6	52.1	56.5	53.5	55.0	57.8	
16.	NPC (MW)	854.0	854.0	854.0	854.0	854.0	854.0	

19.	ANOHR Equation	10^6 / AKW * [546.07 + 67.96 * FEB - 86.35 * MAR + 101.88 * MAY] + 9,691

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2017 - December 2017

	SCHERER 3	Jul '17	Aug '17	Sep '17	Oct '17	Nov '17	Dec '17	Total
1.	EAF (%)	98.0	98.0	3.3	0.0	82.1	98.5	79.0
2.	POF (%)	0.0	0.0	96.7	100.0	16.6	0.0	17.8
3.	EUOF (%)	2.0	2.0	0.0	0.0	1.3	1.5	3.2
4.	EUOR (%)	2.0	2.0	0.0	0.0	1.5	1.5	3.9
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	733.0	724.0	23.0	0.0	588.0	728.0	6872.0
7.	RSH	0.0	9.0	1.0	0.0	4.0	5.0	61.0
8.	UH	11.0	11.0	696.0	744.0	129.0	11.0	1827.0
9.	POH	0.0	0.0	696.0	744.0	120.0	0.0	1560.0
10.	FOH & EFOH	15.0	15.0	0.0	0.0	9.0	11.0	116.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	163.0
12.	Oper MBtu	4031996	3979862	114867	0	2614357	3510904	34756081
13.	Net Gen (MWH)	374755.6	369910.0	10557.6	0.0	236657.6	321276.0	3194953.2
14.	ANOHR (Btu/KWH)	10759.0	10759.0	10880.0	-	11047.0	10928.0	10878.0
15.	NOF %	59.9	59.8	53.8	0.0	47.1	51.7	54.4
16.	NPC (MW)	854.0	854.0	854.0	854.0	854.0	854.0	854.0

19.	ANOHR Equation	10^6 / AKW * [546.07 + 67.96 * FEB - 86.35 * MAR + 101.88 * MAY] + 9,691

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2017 - December 2017

	CRIST 7	Jan '17	Feb '17	Mar '17	Apr '17	May '17	Jun '17	
1.	EAF (%)	99.5	99.4	86.5	72.8	98.4	98.8	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	0.5	0.6	13.5	27.2	1.6	1.2	
4.	EUOR (%)	0.8	0.9	18.3	48.0	1.9	1.4	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	477.0	433.0	445.0	214.0	613.0	631.0	
7.	RSH	263.0	235.0	198.0	312.0	125.0	83.0	
8.	UH	4.0	4.0	100.0	194.0	6.0	6.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	4.0	4.0	4.0	4.0	12.0	9.0	
11.	MOH & EMOH	0.0	0.0	96.0	192.0	0.0	0.0	
12.	Oper MBtu	1438995	1379852	1484323	729558	2081648	2441904	
13.	Net Gen (MWH)	139410.5	133435.1	141836.9	67941.7	199258.0	228878.4	
14.	ANOHR (Btu/KWH)	10322.0	10341.0	10465.0	10738.0	10447.0	10669.0	
15.	NOF %	61.5	64.9	67.1	66.8	68.4	76.4	
16.	NPC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	

19.	ANOHR Equation	10^6 / AKW * [289.45 - 65.63 * JAN - 47.70 * FEB + 85.87 * APR + 114.25 * JUN + 68.08 * JUL + 66.42 * AUG] + 9,556

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2017 - December 2017

	CRIST 7	Jul '17	Aug '17	Sep '17	Oct '17	Nov '17	Dec '17	Total
1.	EAF (%)	98.9	99.1	98.5	99.9	100.0	99.7	96.0
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.	EUOF (%)	1.1	0.9	1.5	0.1	0.0	0.3	4.0
4.	EUOR (%)	1.1	1.0	1.6	0.1	0.0	0.8	5.2
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	737.0	721.0	675.0	675.0	544.0	256.0	6421.0
7.	RSH	0.0	16.0	39.0	68.0	177.0	486.0	2002.0
8.	UH	7.0	7.0	6.0	1.0	0.0	2.0	337.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10.	FOH & EFOH	8.0	7.0	11.0	1.0	0.0	2.0	66.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	288.0
12.	Oper MBtu	2953853	2847546	2552283	2239865	1779434	924963	22854224
13.	Net Gen (MWH)	281533.8	271117.4	246645.1	213931.7	169728.5	89032.9	2182750.0
14.	ANOHR (Btu/KWH)	10492.0	10503.0	10348.0	10470.0	10484.0	10389.0	10470.0
15.	NOF %	80.4	79.2	76.9	66.7	65.7	73.2	71.6
16.	NPC (MW)	475.0	475.0	475.0	475.0	475.0	475.0	475.0

19.	ANOHR Equation	10^6 / AKW * [289.45 - 65.63 * JAN - 47.70 * FEB + 85.87 * APR + 114.25 * JUN + 68.08 * JUL + 66.42 * AUG] + 9,556

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2017 - December 2017

	DANIEL 1	Jan '17	Feb '17	Mar '17	Apr '17	May '17	Jun '17	
1.	EAF (%)	99.3	99.4	99.2	99.9	54.3	99.0	
2.	POF (%)	0.0	0.0	0.0	0.0	45.2	0.0	
3.	EUOF (%)	0.7	0.6	0.8	0.1	0.5	1.0	
4.	EUOR (%)	1.4	1.2	1.2	1.9	1.3	1.2	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	359.0	337.0	487.0	53.0	315.0	584.0	
7.	RSH	380.0	331.0	250.0	666.0	89.0	129.0	
8.	UH	5.0	4.0	6.0	1.0	340.0	7.0	
9.	POH	0.0	0.0	0.0	0.0	336.0	0.0	
10.	FOH & EFOH	5.0	4.0	6.0	1.0	4.0	7.0	
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	846457	888193	1200961	160000	893924	1786022	
13.	Net Gen (MWH)	79711.6	84421.0	113544.6	13947.0	81846.2	167136.6	
14.	ANOHR (Btu/KWH)	10619.0	10521.0	10577.0	11472.0	10922.0	10686.0	
15.	NOF %	43.5	49.1	45.7	51.6	50.9	56.1	
16.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	

19.	ANOHR Equation	10^6 / AKW * [190.55 + 259.92 * APR + 111.26 * MAY + 74.52 * JUN + 183.30 * OCT + 100.15 * NOV] + 9,760

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2017 - December 2017

	DANIEL 1	Jul '17	Aug '17	Sep '17	Oct '17	Nov '17	Dec '17	Total
1.	EAF (%)	98.8	98.8	98.8	73.9	79.6	87.0	90.5
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	3.8
3.	EUOF (%)	1.2	1.2	1.2	26.1	20.4	13.0	5.7
4.	EUOR (%)	1.2	1.2	1.3	55.7	34.6	45.8	9.2
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	719.0	735.0	702.0	154.0	278.0	115.0	4838.0
7.	RSH	16.0	0.0	9.0	396.0	296.0	532.0	3094.0
8.	UH	9.0	9.0	9.0	194.0	147.0	97.0	828.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	336.0
10.	FOH & EFOH	9.0	9.0	9.0	2.0	3.0	1.0	60.0
11.	MOH & EMOH	0.0	0.0	0.0	192.0	144.0	96.0	432.0
12.	Oper MBtu	2497151	2500603	2195346	436054	729281	358421	14492413
13.	Net Gen (MWH)	241808.0	241861.2	211212.8	38777.6	66437.2	34476.8	1375180.6
14.	ANOHR (Btu/KWH)	10327.0	10339.0	10394.0	11245.0	10977.0	10396.0	10539.0
15.	NOF %	65.9	64.5	59.0	49.4	46.9	58.8	55.7
16.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	510.0

19.	ANOHR Equation	10^6 / AKW * [190.55 + 259.92 * APR + 111.26 * MAY + 74.52 * JUN + 183.30 * OCT + 100.15 * NOV] + 9,760

Issued by: S. W. Connally, Jr.

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2017 - December 2017

	DANIEL 2	Jan '17	Feb '17	Mar '17	Apr '17	May '17	Jun '17	
1.	EAF (%)	92.7	70.8	41.6	0.0	9.5	98.5	
2.	POF (%)	0.0	0.0	58.1	100.0	90.3	0.0	
3.	EUOF (%)	7.3	29.2	0.3	0.0	0.2	1.5	
4.	EUOR (%)	12.6	42.0	1.6	0.0	2.3	2.0	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	374.0	271.0	123.0	0.0	42.0	542.0	
7.	RSH	316.0	205.0	186.0	0.0	29.0	169.0	
8.	UH	54.0	196.0	434.0	720.0	673.0	9.0	
9.	POH	0.0	0.0	432.0	720.0	672.0	0.0	
10.	FOH & EFOH	6.0	4.0	2.0	0.0	1.0	11.0	
11.	MOH & EMOH	48.0	192.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	940218	719915	289825	0	112463	1691342	
13.	Net Gen (MWH)	85381.2	69732.2	28481.2	0.0	10398.8	155726.2	
14.	ANOHR (Btu/KWH)	11012.0	10324.0	10176.0	-	10815.0	10861.0	
15.	NOF %	44.8	50.5	45.4	0.0	48.5	56.3	
16.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	

19.	ANOHR Equation	10^6 / AKW * [575.65 - 103.95 * FEB - 185.22 * MAR + 105.27 * JUN - 106.15 * NOV] + 8,491

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2017 - December 2017

	DANIEL 2	Jul '17	Aug '17	Sep '17	Oct '17	Nov '17	Dec '17	Total
1.	EAF (%)	98.4	98.4	98.8	99.5	99.3	99.9	75.7
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	20.8
3.	EUOF (%)	1.6	1.6	1.2	0.5	0.7	0.1	3.5
4.	EUOR (%)	1.6	1.6	1.6	1.5	1.7	2.1	7.2
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	732.0	732.0	540.0	264.0	291.0	47.0	3958.0
7.	RSH	0.0	0.0	171.0	476.0	425.0	696.0	2673.0
8.	UH	12.0	12.0	9.0	4.0	5.0	1.0	2129.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1824.0
10.	FOH & EFOH	12.0	12.0	9.0	4.0	5.0	1.0	67.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	240.0
12.	Oper MBtu	2501203	2457640	1649783	747821	700927	117571	11928708
13.	Net Gen (MWH)	244951.8	239840.0	157708.0	70185.0	66463.8	10660.2	1139528.4
14.	ANOHR (Btu/KWH)	10211.0	10247.0	10461.0	10655.0	10546.0	11029.0	10468.0
15.	NOF %	65.6	64.2	57.3	52.1	44.8	44.5	56.5
16.	NPC (MW)	510.0	510.0	510.0	510.0	510.0	510.0	510.0

19.	ANOHR Equation	10^6 / AKW * [575.65 - 103.95 * FEB - 185.22 * MAR + 105.27 * JUN - 106.15 * NOV] + 8,491

Issued by: S. W. Connally, Jr.

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2017 - December 2017

	SMITH 3	Jan '17	Feb '17	Mar '17	Apr '17	May '17	Jun '17	
1.	EAF (%)	83.5	99.6	99.5	69.7	98.5	99.6	
2.	POF (%)	0.0	0.0	0.0	30.0	0.0	0.0	
3.	EUOF (%)	16.5	0.4	0.5	0.3	1.5	0.4	
4.	EUOR (%)	17.1	0.4	0.5	0.4	1.5	0.4	
5.	PH	744.0	672.0	743.0	720.0	744.0	720.0	
6.	SH	597.0	669.0	739.0	502.0	716.0	704.0	
7.	RSH	24.0	0.0	0.0	0.0	17.0	13.0	
8.	UH	123.0	3.0	4.0	218.0	11.0	3.0	
9.	POH	0.0	0.0	0.0	216.0	0.0	0.0	
10.	FOH & EFOH	3.0	3.0	4.0	2.0	11.0	3.0	
11.	MOH & EMOH	120.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	2075544	2403819	2640794	1848289	2384287	2330875	
13.	Net Gen (MWH)	301152.6	344485.4	380298.7	265635.1	341099.7	332364.9	
14.	ANOHR (Btu/KWH)	6892.0	6978.0	6944.0	6958.0	6990.0	7013.0	
15.	NOF %	86.4	88.2	92.3	94.9	81.9	84.9	
16.	NPC (MW)	584.0	584.0	557.4	557.4	581.4	556.0	

19.	ANOHR Equation	10^6 / AKW * [21.08 + 44.81 * FEB + 27.39 * MAR + 36.15 * APR + 45.63 * MAY + 55.90 * JUN - 43.01 * OCT] + 6,850

Issued by: S. W. Connally, Jr.

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2017 - December 2017

	SMITH 3	Jul '17	Aug '17	Sep '17	Oct '17	Nov '17	Dec '17	Total
1.	EAF (%)	99.5	99.5	99.4	99.5	99.4	70.6	93.1
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	29.0	4.9
3.	EUOF (%)	0.5	0.5	0.6	0.5	0.6	0.4	1.9
4.	EUOR (%)	0.5	0.5	0.6	0.5	0.6	0.6	2.0
5.	PH	744.0	744.0	720.0	744.0	721.0	744.0	8760.0
6.	SH	740.0	740.0	716.0	740.0	717.0	525.0	8105.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	54.0
8.	UH	4.0	4.0	4.0	4.0	4.0	219.0	601.0
9.	POH	0.0	0.0	0.0	0.0	0.0	216.0	432.0
10.	FOH & EFOH	4.0	4.0	4.0	4.0	4.0	3.0	49.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	120.0
12.	Oper MBtu	2510613	2482748	2383004	2433256	2401296	1769006	27663531
13.	Net Gen (MWH)	364226.4	360184.0	345663.5	357568.9	348367.3	256638.0	3997684.5
14.	ANOHR (Btu/KWH)	6893.0	6893.0	6894.0	6805.0	6893.0	6893.0	6920.0
15.	NOF %	88.5	87.5	86.8	86.7	87.2	83.7	87.2
16.	NPC (MW)	556.0	556.0	556.0	557.4	557.4	584.0	565.6

19.	ANOHR Equation	10^6 / AKW * [21.08 + 44.81 * FEB + 27.39 * MAR + 36.15 * APR + 45.63 * MAY + 55.90 * JUN - 43.01 * OCT] + 6,850

Issued by: S. W. Connally, Jr.

Planned Outage Schedules (Estimated)

Gulf Power Company

Period of: January 2017 - December 2017

Plant & Unit	Planned Outage Dates			Reason for Outage
Scherer 3	09/02/17	-	11/05/17	Condenser retube
Smith 3	04/22/17	-	04/30/17	Borescope inspection
Smith 3	12/02/17	-	12/10/17	Borescope inspection
Daniel 1	05/01/17	-	05/14/17	Common scrubber outage
Daniel 2	03/14/17	-	05/28/17	Generator rotor rewind

Issued by: S. W. Connally, Jr.

Notes Regarding Estimated Planned Outage Schedules

Gulf Power Company

Period of: January 2017 - December 2017

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 2017 - December 2017, the outages shown below are currently planned and could be rescheduled for the target period.

Plant & Unit	Planned Outage Dates	Reason for Outage
None		

TAMPA ELECTRIC COMPANY

FUEL AND PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 49
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 2015 – DECEMBER 2015

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2015 THROUGH DECEMBER 2015

1.	Actual End-of-Period True-up: Over/(Under) Recovery	($245,925)
2.	Less: Actual/Estimated Over/(Under) Recovery Per Order No. PSC-15-0586-FOF-EI For the January 2015 Through December 2015 Period	2,203,769
3.	Final True-up: Over/(Under) Recovery to Be Carried Forward to the January 2017 Through December 2017 Period	**($2,449,694)**

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY 2015 THROUGH DECEMBER 2015

	Actual Jan-15	Actual Feb-15	Actual Mar-15	Actual Apr-15	Actual May-15	Actual Jun-15	Actual Jul-15	Actual Aug-15	Actual Sep-15	Actual Oct-15	Actual Nov-15	Actual Dec-15	Total
1 UNIT POWER CAPACITY CHARGES	0	0	0	0	0	0	0	0	0	0	0	0	0
2 CAPACITY PAYMENTS TO COGENERATORS	1,261,780	1,261,780	1,261,780	1,261,780	1,261,780	1,261,780	1,261,780	1,261,780	1,261,780	1,261,780	1,261,780	1,261,780	15,141,360
3 SCHEDULE J,D, & EMERG CAPACITY CHARGES	1,438,481	1,452,587	1,476,211	1,490,199	1,599,706	1,602,103	1,648,716	1,656,960	1,663,831	1,620,770	1,579,383	1,436,485	18,665,432
4 INCREMENTAL SECURITY O&M COSTS	0	0	0	0	0	0	0	0	0	0	0	0	0
5 (CAPACITY REVENUES)	(109,297)	(97,554)	(62,789)	(170,898)	(13,413)	(8,635)	(16,785)	(11,793)	(15,432)	(38,041)	(22,307)	(215,068)	(782,012)
6 TOTAL CAPACITY DOLLARS	2,590,964	2,616,813	2,675,202	2,581,081	2,848,073	2,855,248	2,893,711	2,906,947	2,910,179	2,844,509	2,818,856	2,483,197	33,024,780
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	2,590,964	2,616,813	2,675,202	2,581,081	2,848,073	2,855,248	2,893,711	2,906,947	2,910,179	2,844,509	2,818,856	2,483,197	33,024,780
9 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	2,397,187	2,287,835	2,347,863	2,533,298	2,742,593	3,074,206	3,169,350	2,995,399	3,146,471	2,882,777	2,640,400	2,455,017	32,672,396
10 PRIOR PERIOD TRUE-UP PROVISION	(2,794)	(2,794)	(2,794)	(2,794)	(2,794)	(2,794)	(2,794)	(2,794)	(2,794)	(2,794)	(2,794)	(2,792)	(33,526)
11 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	2,394,393	2,285,041	2,345,069	2,530,504	2,739,799	3,071,412	3,166,556	2,992,605	3,143,677	2,879,983	2,637,606	2,452,225	32,638,870
12 TRUE-UP PROVISION FOR PERIOD OVER/(UNDER) RECOVERY (Line 11 - Line 8)	(196,571)	(331,772)	(330,133)	(50,577)	(108,274)	216,164	272,845	85,658	233,498	35,474	(181,250)	(30,972)	(385,910)
13 INTEREST PROVISION FOR PERIOD	1	(20)	(46)	(46)	(59)	(63)	(43)	(32)	(20)	(6)	(14)	(53)	(401)
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	106,860	(86,916)	(415,914)	(743,299)	(791,128)	(896,667)	(677,772)	(402,176)	(313,756)	(77,484)	(39,222)	(217,692)	106,860
16 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS PERIOD	2,794	2,794	2,794	2,794	2,794	2,794	2,794	2,794	2,794	2,794	2,794	2,792	33,526
17 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 12 - 16)	(86,916)	(415,914)	(743,299)	(791,128)	(896,667)	(677,772)	(402,176)	(313,756)	(77,484)	(39,222)	(217,692)	(245,925)	**(245,925)**

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY 2015 THROUGH DECEMBER 2015

	Actual Jan-15	Actual Feb-15	Actual Mar-15	Actual Apr-15	Actual May-15	Actual Jun-15	Actual Jul-15	Actual Aug-15	Actual Sep-15	Actual Oct-15	Actual Nov-15	Actual Dec-15	Total
1 BEGINNING TRUE-UP AMOUNT	106,860	(86,916)	(415,914)	(743,299)	(791,128)	(896,667)	(677,772)	(402,176)	(313,756)	(77,484)	(39,222)	(217,692)	106,860
2 ENDING TRUE-UP AMOUNT BEFORE INTEREST	(86,917)	(415,894)	(743,253)	(791,082)	(896,608)	(677,709)	(402,133)	(313,724)	(77,464)	(39,216)	(217,678)	(245,872)	(245,524)
3 TOTAL BEGINNING & ENDING TRUE-UP AMT. (LINE 1 + LINE 2)	19,943	(502,810)	(1,159,167)	(1,534,381)	(1,687,736)	(1,574,376)	(1,079,905)	(715,900)	(391,220)	(116,700)	(256,900)	(463,564)	(138,664)
4 AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	9,972	(251,405)	(579,584)	(767,191)	(843,868)	(787,188)	(539,953)	(357,950)	(195,610)	(58,350)	(128,450)	(231,782)	(69,332)
5 INTEREST RATE % - 1ST DAY OF MONTH	0.100	0.100	0.090	0.090	0.060	0.100	0.080	0.110	0.110	0.130	0.120	0.150	NA
6 INTEREST RATE % - 1ST DAY OF NEXT MONTH	0.100	0.090	0.090	0.060	0.100	0.080	0.110	0.110	0.130	0.120	0.150	0.400	NA
7 TOTAL (LINE 5 + LINE 6)	0.200	0.190	0.180	0.150	0.160	0.180	0.190	0.220	0.240	0.250	0.270	0.550	NA
8 AVERAGE INTEREST RATE % (50% OF LINE 7)	0.100	0.095	0.090	0.075	0.080	0.090	0.095	0.110	0.120	0.125	0.135	0.275	NA
9 MONTHLY AVERAGE INTEREST RATE % (LINE 8/12)	0.008	0.008	0.008	0.006	0.007	0.008	0.008	0.009	0.010	0.010	0.011	0.023	NA
10 INTEREST PROVISION (LINE 4 X LINE 9)	1	(20)	(46)	(46)	(59)	(63)	(43)	(32)	(20)	(6)	(14)	(53)	(401)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2015 THROUGH DECEMBER 2015

	(1) ACTUAL	(2) ACTUAL/ ESTIMATED	(3) VARIANCE (1) - (2)	(4) % CHANGE (3)/(2)
1 UNIT POWER CAPACITY CHARGES	$0	$0	$0	0.00%
2 CAPACITY PAYMENTS TO COGENERATORS	15,141,360	15,141,360	0	0.00%
3 SCHEDULE J & D CAPACITY CHARGES	18,665,432	$18,321,586	343,846	2.00%
4 INCREMENTAL SECURITY O&M COSTS	0	0	0	0.00%
5 (CAPACITY REVENUES)	(782,012)	(925,170)	143,158	-15.47%
6 TOTAL CAPACITY DOLLARS	$33,024,780	$32,537,776	$487,004	1.50%
7 JURISDICTIONAL PERCENTAGE	100.00000%	100.00000%	0.00000%	0.00%
8 JURISDICTIONAL CAPACITY DOLLARS	$33,024,780	$32,537,776	$487,004	1.50%
9 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	32,672,396	34,630,513	(1,958,117)	-5.65%
10 PRIOR PERIOD TRUE-UP PROVISION	(33,526)	(33,526)	0	0.00%
11 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	$32,638,870	$34,596,987	($1,958,117)	-5.66%
12 TRUE-UP PROVISION FOR PERIOD OVER/(UNDER) RECOVERY (Line 11 - Line 8)	($385,910)	$2,059,211	($2,445,121)	-118.74%
13 INTEREST PROVISION FOR PERIOD	(401)	4,172	(4,573)	-109.61%
14 OTHER ADJUSTMENT	0	0	0	0.00%
15 TRUE-UP AND INT. PROVISION BEGINNING OF PERIOD - OVER/(UNDER) RECOVERY	106,860	106,860	0	0.00%
16 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS PERIOD	33,526	33,526	0	0.00%
17 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 12 - 16)	($245,925)	$2,203,769	($2,449,694)	-111.16%

EXHIBIT TO THE TESTIMONY OF
PENELOPE A. RUSK

DOCUMENT NO. 2

FINAL FUEL AND PURCHASED POWER OVER/(UNDER)RECOVERY
FOR
JANUARY 2015 – DECEMBER 2015

TAMPA ELECTRIC COMPANY
FINAL FUEL AND PURCHASED POWER OVER/(UNDER) RECOVERY
FOR THE PERIOD
JANUARY 2015 THROUGH DECEMBER 2015

1 TOTAL FUEL COSTS FOR THE PERIOD	$696,924,863
2 JURISDICTIONAL FUEL COSTS (INCL. ALL ADJUSTMENTS)	696,924,863
3 JURISDICTIONAL FUEL REVENUES APPLICABLE TO THE PERIOD	745,466,798
4 ACTUAL OVER/(UNDER) RECOVERED FUEL COSTS FOR THE PERIOD (LINE 3 - LINE 2)	48,541,935
5 ADJUSTMENTS	0
6 INTEREST	25,926
7 TRUE-UP COLLECTED	(13,386,199)
8 PRIOR PERIOD TRUE-UP (ACTUAL ENDING 12/14)	10,467,182
9 ACTUAL OVER/(UNDER) RECOVERY FOR THE PERIOD (LINE 4 + LINE 5 + LINE 6 + LINE 7 + LINE 8)	45,648,849
10 PROJECTED OVER-RECOVERY PER PROJECTION FILED 9/1/15 (SCHEDULE E1-A LINE 3)	27,590,550
11 FINAL FUEL OVER/(UNDER) RECOVERY (LINE 9 - LINE 10)	**$18,058,299**

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 3

ACTUAL FUEL AND PURCHASED POWER TRUE-UP

VS.

ORIGINAL ESTIMATES

JANUARY 2015 – DECEMBER 2015

TAMPA ELECTRIC COMPANY
CALCULATION OF TRUE-UP AMOUNT
ACTUAL vs. ORIGINAL ESTIMATES
FOR THE PERIOD
JANUARY 2015 THROUGH DECEMBER 2015

		ACTUAL	ESTIMATED	VARIANCE AMOUNT	%
A	1. FUEL COST OF SYSTEM NET GENERATION	$647,742,170	$698,913,664	($51,171,494)	(7.3)
	2. FUEL COST OF POWER SOLD	2,726,958	5,966,348	(3,239,390)	(54.3)
	2a. GAINS FROM SALES	496,810	581,934	(85,124)	(14.6)
	3. FUEL COST OF PURCHASED POWER	19,046,419	6,810,170	12,236,249	179.7
	3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0
	3b. PAYMENT TO QUALIFIED FACILITIES	8,657,036	8,238,900	418,136	5.1
	4. ENERGY COST OF ECONOMY PURCHASES	17,356,085	16,990,090	365,995	2.2
	6a. ADJ. - BIG BEND UNITS 1-4 IGNITERS CONVERSION PROJEC	3,689,743	3,310,090	379,653	11.5
	6b. ADJ. - POLK 1 CONVERSION DEPRECIATION & ROI	4,109,281	4,114,495	(5,214)	(0.1)
	6c. ADJ. - POLK WARM GAS CLEANUP	(452,103)	0	(452,103)	0.0
	7. ADJUSTED TOTAL FUEL & NET PWR.TRANS. (SUM OF LINES A1 THRU 6c)	$696,924,863	$731,829,127	($34,904,264)	(4.8)
C	1. JURISDICTIONAL FUEL REVENUE	$733,770,327	$718,288,323	$15,482,004	2.2
	2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0
	2a. TRUE-UP PROVISION	13,386,199	13,386,207	(8)	0.0
	2b. INCENTIVE PROVISION	(1,689,728)	(1,689,728)	0	0.0
	2c. ADJUSTMENT	0	0	0	0.0
	3. JURIS. FUEL REVENUE APPL. TO PERIOD (Sum of Lines C1 through C2c)	745,466,798	729,984,802	15,481,996	2.1
	6d.JURISD. TOTAL FUEL & NET PWR. TRANS.	696,924,863	731,829,127	(34,904,264)	(4.8)
	7. TRUE-UP PROV.- THIS PER. (LINE C3-C6d)	48,541,935	(1,844,325)	50,386,260	(2,732.0)
	7a. ADJUSTMENTS	0	0	0	0.0
	8. INTEREST PROVISION - THIS PERIOD	25,856	5,368	20,488	381.7
	8a. PRIOR MONTHS INTEREST ADJUSTMENT	70	0	70	0.0
	8b. TOTAL TRUE-UP AMOUNT FOR PERIOD (LINE 7 through 8a)	$48,567,861	($1,838,957)	$50,406,818	(2,741.1)
	9.TRUE-UP & INT. PROV. BEG. OF PERIOD (Beginning January 2015)	10,467,182	13,386,207	(2,919,025)	(21.8)
	10.TRUE-UP COLLECTED (REFUNDED)	(13,386,199)	(13,386,207)	8	0.0
	11.END OF PERIOD TOTAL NET TRUE-UP (LINE C8b through C10)	$45,648,849	($1,838,957)	$47,487,806	(2,582.3)

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 2015

SCHEDULES A1 AND A2
AND
SCHEDULES A6 THROUGH A9
AND
SCHEDULE A12

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 AND A2

DECEMBER 2015

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: December 2015

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	49,770,094	51,912,405	(2,142,311)	-4.1%	1,523,029	1,410,640	112,389	8.0%	3.26784	3.68006	(0.41222)	-11.2%
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	484,479	395,382	89,097	22.5%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4b. Adjustments - Polk 1 Conversion Depreciation & ROI	330,819	331,623	(804)	-0.2%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4c. Adjustments - Polk Warm Gas Cleanup	(25,760)	0	(25,760)	0.0%	(4,846)	0	(4,846)	0.0%	0.53157	0.00000	0.53157	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**50,559,632**	**52,639,410**	**(2,079,778)**	**-4.0%**	**1,518,183**	**1,410,640**	**107,543**	**7.6%**	**3.33027**	**3.73160**	**(0.40133)**	**-10.8%**
6. Fuel Cost of Purchased Power - Firm (A7)	461,388	215,800	245,588	113.8%	12,351	5,270	7,081	134.4%	3.73563	4.09488	(0.35924)	-8.8%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	114,246	1,072,240	(957,994)	-89.3%	4,166	36,170	(32,004)	-88.5%	2.74234	2.96445	(0.22210)	-7.5%
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 (A8)	448,948	714,960	(266,012)	-37.2%	21,672	20,960	712	3.4%	2.07156	3.41107	(1.33951)	-39.3%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**1,024,582**	**2,003,000**	**(978,418)**	**-48.8%**	**38,189**	**62,400**	**(24,211)**	**-38.8%**	**2.68292**	**3.20994**	**(0.52701)**	**-16.4%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,556,372**	**1,473,040**	**83,332**	**5.7%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	5,741	17,700	(11,959)	-67.6%	295	580	(285)	-49.1%	1.94610	3.05172	(1.10562)	-36.2%
15. Fuel Cost of Sch. C/CB Sales (A6)	184,792	0	184,792	0.0%	10,432	0	10,432	0.0%	1.77140	0.00000	1.77140	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)	89,381	399,960	(310,579)	-77.7%	4,605	13,210	(8,605)	-65.1%	1.94096	3.02771	(1.08675)	-35.9%
18. Gains on Sales	(16,703)	37,174	(53,877)	-144.9%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES	**263,211**	**454,834**	**(191,623)**	**-42.1%**	**15,332**	**13,790**	**1,542**	**11.2%**	**1.71674**	**3.29829**	**(1.58155)**	**-48.0%**
(LINE 14 + 15 + 16 + 17 + 18)												
20. Net Inadvertant Interchange					910	0	910	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					1,793	0	1,793	0.0%				
22. Interchange and Wheeling Losses					2,030	231	1,799	780.0%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS	**51,321,003**	**54,187,576**	**(2,866,573)**	**-5.3%**	**1,541,713**	**1,459,019**	**82,694**	**5.7%**	**3.32883**	**3.71397**	**(0.38514)**	**-10.4%**
(LINE 5 + 12 - 19 + 20 + 21 - 22)												
24. Net Unbilled	529,650 (a)	794,604 (a)	(264,954)	-33.3%	15,911	21,395	(5,484)	-25.6%	3.32883	3.71397	(0.38514)	-10.4%
25. Company Use	90,810 (a)	101,763 (a)	(10,953)	-10.8%	2,728	2,740	(12)	-0.4%	3.32881	3.71398	(0.38517)	-10.4%
26. T & D Losses	2,943,891 (a)	2,428,541 (a)	515,350	21.2%	88,436	65,389	23,047	35.2%	3.32883	3.71397	(0.38514)	-10.4%
27. System KWH Sales	51,321,003	54,187,576	(2,866,573)	-5.3%	1,434,638	1,369,495	65,143	4.8%	3.57728	3.95676	(0.37948)	-9.6%
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	51,321,003	54,187,576	(2,866,573)	-5.3%	1,434,638	1,369,495	65,143	4.8%	3.57728	3.95676	(0.37948)	-9.6%
30. Jurisdictional Loss Multiplier									1.00000	1.00000	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	51,321,003	54,187,576	(2,866,573)	-5.3%	1,434,638	1,369,495	65,143	4.8%	3.57728	3.95676	(0.37948)	-9.6%
32. Other	0	0	0	0.0%	1,434,638	1,369,495	65,143	4.8%	0.00000	0.00000	0.00000	0.0%
33. True-up *	(1,115,512)	(1,115,520)	8	0.0%	1,434,638	1,369,495	65,143	4.8%	(0.07776)	(0.08145)	0.00370	-4.5%
34. Total Jurisdictional Fuel Cost (Excl. GPIF)	50,205,491	53,072,056	(2,866,565)	-5.4%	1,434,638	1,369,495	65,143	4.8%	3.49952	3.87530	(0.37578)	-9.7%
35. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
36. Fuel Cost Adjusted for Taxes (Excl. GPIF)	50,241,639	53,110,268	(2,868,629)	-5.4%	1,434,638	1,369,495	65,143	4.8%	3.50204	3.87809	(0.37605)	-9.7%
37. GPIF * (Already Adjusted for Taxes)	140,807	140,807	0	0.0%	1,434,638	1,369,495	65,143	4.8%	0.00981	0.01028	(0.00047)	-4.5%
38. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**50,382,446**	**53,251,075**	**(2,868,629)**	**-5.4%**	**1,434,638**	**1,369,495**	**65,143**	**4.8%**	**3.51185**	**3.88837**	**(0.37652)**	**-9.7%**
39. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.512**	**3.888**	**(0.376)**	**-9.7%**

* 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 2015

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	647,742,170	698,913,664	(51,171,494)	-7.3%	19,037,980	18,831,670	206,310	1.1%	3.40237	3.71137	(0.30901)	-8.3%
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	3,689,743	3,310,090	379,653	11.5%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4b. Adjustments - Polk 1 Conversion Depreciation & ROI	4,109,281	4,114,495	(5,214)	-0.1%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4c. Adjustments - Polk Warm Gas Cleanup	(452,103)	0	(452,103)	0.0%	(21,290)	0	(21,290)	0.0%	2.12355	0.00000	2.12355	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**655,089,091**	**706,338,249**	**(51,249,158)**	**-7.3%**	**19,016,690**	**18,831,670**	**185,020**	**1.0%**	**3.44481**	**3.75080**	**(0.30599)**	**-8.2%**
6. Fuel Cost of Purchased Power - Firm (A7)	19,046,419	6,810,170	12,236,249	179.7%	450,462	154,460	296,002	191.6%	4.22820	4.40902	(0.18082)	-4.1%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	17,356,085	16,990,090	365,995	2.2%	423,960	509,460	(85,500)	-16.8%	4.09380	3.33492	0.75888	22.8%
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 (A8)	8,657,036	8,238,900	418,136	5.1%	340,729	256,140	84,589	33.0%	2.54074	3.21656	(0.67582)	-21.0%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**45,059,540**	**32,039,160**	**13,020,380**	**40.6%**	**1,215,151**	**920,060**	**295,091**	**32.1%**	**3.70814**	**3.48229**	**0.22585**	**6.5%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**20,231,841**	**19,751,730**	**480,111**	**2.4%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	120,807	321,850	(201,043)	-62.5%	5,357	10,330	(4,973)	-48.1%	2.25512	3.11568	(0.86056)	-27.6%
15. Fuel Cost of Sch. C/CB Sales (A6)	1,960,374	0	1,960,374	0.0%	80,140	0	80,140	0.0%	2.44619	0.00000	2.44619	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)	645,777	5,644,498	(4,998,721)	-88.6%	29,782	178,480	(148,698)	-83.3%	2.16835	3.16254	(0.99419)	-31.4%
18. Gains on Sales	496,810	581,934	(85,124)	-14.6%								
19. TOTAL FUEL COST AND GAINS OF POWER SALES	**3,223,768**	**6,548,282**	**(3,324,514)**	**-50.8%**	**115,279**	**188,810**	**(73,531)**	**-38.9%**	**2.79649**	**3.46819**	**(0.67169)**	**-19.4%**
(LINE 14 + 15 + 16 + 17 + 18)												
20. Net Inadvertant Interchange					(304)	0	(304)	0.0%				
21. Wheeling Rec'd. less Wheeling Delv'd.					33,155	0	33,155	0.0%				
22. Interchange and Wheeling Losses					35,185	3,197	31,988	1000.6%				
23. TOTAL FUEL AND NET POWER TRANSACTIONS	**696,924,863**	**731,829,127**	**(34,904,264)**	**-4.8%**	**20,114,228**	**19,559,723**	**554,505**	**2.8%**	**3.46484**	**3.74151**	**(0.27668)**	**-7.4%**
(LINE 5 + 12 - 19 + 20 + 21 - 22)												
24. Net Unbilled	4,073,394 (a)	2,291,850 (a)	1,781,544	77.7%	115,229	61,891	53,338	86.2%	3.53504	3.70304	(0.16800)	-4.5%
25. Company Use	1,221,660 (a)	1,230,985 (a)	(9,325)	-0.8%	35,190	32,880	2,310	7.0%	3.47161	3.74387	(0.27226)	-7.3%
26. T & D Losses	33,025,227 (a)	31,165,788 (a)	1,859,439	6.0%	958,411	834,552	123,859	14.8%	3.44583	3.73443	(0.28860)	-7.7%
27. System KWH Sales	696,924,863	731,829,127	(34,904,264)	-4.8%	19,005,398	18,630,400	374,998	2.0%	3.66698	3.92815	(0.26116)	-6.6%
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	696,924,863	731,829,127	(34,904,264)	-4.8%	19,005,398	18,630,400	374,998	2.0%	3.66698	3.92815	(0.26116)	-6.6%
30. Jurisdictional Loss Multiplier									1.00000	1.00000	0.00000	0.0%
31. Jurisdictional KWH Sales Adjusted for Line Losses	696,924,863	731,829,127	(34,904,264)	-4.8%	19,005,398	18,630,400	374,998	2.0%	3.66698	3.92815	(0.26116)	-6.6%
32. Other	0	0	0	0.0%	19,005,398	18,630,400	374,998	2.0%	0.00000	0.00000	0.00000	0.0%
33. True-up *	(13,386,199)	(13,386,207)	8	0.0%	19,005,398	18,630,400	374,998	2.0%	(0.07043)	(0.07185)	0.00142	-2.0%
34. Total Jurisdictional Fuel Cost (Excl. GPIF)	683,538,664	718,442,920	(34,904,256)	-4.9%	19,005,398	18,630,400	374,998	2.0%	3.59655	3.85629	(0.25974)	-6.7%
35. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
36. Fuel Cost Adjusted for Taxes (Excl. GPIF)	684,030,811	718,960,200	(34,929,389)	-4.9%	19,005,398	18,630,400	374,998	2.0%	3.59914	3.85907	(0.25993)	-6.7%
37. GPIF * (Already Adjusted for Taxes)	1,689,728	1,689,728	0	0.0%	19,005,398	18,630,400	374,998	2.0%	0.00889	0.00907	(0.00018)	-2.0%
38. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**685,720,539**	**720,649,928**	**(34,929,389)**	**-4.8%**	**19,005,398**	**18,630,400**	**374,998**	**2.0%**	**3.60803**	**3.86814**	**(0.26011)**	**-6.7%**
39. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.608**	**3.868**	**(0.260)**	**-6.7%**

* Based on Jurisdictional Sales (a) included for informational purposes only

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: December 2015

	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	49,770,094	51,912,405	(2,142,311)	-4.1%	647,742,170	698,913,664	(51,171,494)	-7.3%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	279,914	417,660	(137,746)	-33.0%	2,726,958	5,966,348	(3,239,390)	-54.3%
2a. GAINS FROM SALES	(16,703)	37,174	(53,877)	-144.9%	496,810	581,934	(85,124)	-14.6%
3. FUEL COST OF PURCHASED POWER	461,388	215,800	245,588	113.8%	19,046,419	6,810,170	12,236,249	179.7%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	448,948	714,960	(266,012)	-37.2%	8,657,036	8,238,900	418,136	5.1%
4. ENERGY COST OF ECONOMY PURCHASES	114,246	1,072,240	(957,994)	-89.3%	17,356,085	16,990,090	365,995	2.2%
5. TOTAL FUEL & NET POWER TRANSACTION	50,531,465	53,460,571	(2,929,106)	-5.5%	689,577,942	724,404,542	(34,826,600)	-4.8%
6a. ADJ. - BIG BEND UNITS 1-4 IGNITERS CONVERSION PROJECT	484,479	395,382	89,097	22.5%	3,689,743	3,310,090	379,653	11.5%
6b. ADJ. - POLK 1 CONVERSION DEPRECIATION & ROI	330,819	331,623	(804)	-0.2%	4,109,281	4,114,495	(5,214)	-0.1%
6c. ADJ. - POLK WARM GAS CLEANUP	(25,760)	0	(25,760)	0.0%	(452,103)	0	(452,103)	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	51,321,003	54,187,576	(2,866,573)	-5.3%	696,924,863	731,829,127	(34,904,264)	-4.8%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,434,638	1,369,495	65,143	4.8%	19,005,398	18,630,400	374,998	2.0%
2. NONJURISDICTIONAL SALES	0	0	0	0.0%	0	0	0	0.0%
3. TOTAL SALES	1,434,638	1,369,495	65,143	4.8%	19,005,398	18,630,400	374,998	2.0%
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 2015

	CURRENT MONTH				PERIOD TO DATE			
			DIFFERENCE				DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
C. TRUE-UP CALCULATION								
1. JURISDICTIONAL FUEL REVENUE	54,838,456	52,196,822	2,641,634	5.1%	733,770,327	718,288,323	15,482,004	2.2%
2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	1,115,512	1,115,520	(8)	0.0%	13,386,199	13,386,207	(8)	0.0%
2b. INCENTIVE PROVISION	(140,807)	(140,807)	0	0.0%	(1,689,728)	(1,689,728)	0	0.0%
2c. ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	55,813,161	53,171,535	2,641,626	5.0%	745,466,798	729,984,802	15,481,996	2.1%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	51,321,003	54,187,576	(2,866,573)	-5.3%	696,924,863	731,829,127	(34,904,264)	-4.8%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	1.0000000	1.0000000	0.0000000	0.0%	-	-	-	-
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	51,321,003	54,187,576	(2,866,573)	-5.3%	696,924,863	731,829,127	(34,904,264)	-4.8%
6a. JURISDIC. LOSS MULTIPLIER	1.00000	1.00000	0.00000	0.0%	-	-	-	-
6b. (LINE C6 x LINE C6a)	51,321,003	54,187,576	(2,866,573)	-5.3%	696,924,863	731,829,127	(34,904,264)	-4.8%
6c. OTHER	0	0	0	0.0%	0	0	0	0.0%
6d. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6c)	51,321,003	54,187,576	(2,866,573)	-5.3%	696,924,863	731,829,127	(34,904,264)	-4.8%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6d)	4,492,158	(1,016,041)	5,508,199	-542.1%	48,541,935	(1,844,325)	50,386,260	-2732.0%
8. INTEREST PROVISION FOR THE MONTH	10,109	(147)	10,256	-6976.9%	25,856	5,368	20,488	381.7%
8a. PRIOR MONTHS INTEREST ADJUSTMENT	0	0	0	0.0%	70	0	70	0.0%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	42,262,094	292,751	41,969,343	14336.2%	----------	NOT APPLICABLE	----------	
10. TRUE-UP COLLECTED (REFUNDED)	(1,115,512)	(1,115,520)	8	0.0%	----------	NOT APPLICABLE	----------	
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	45,648,849	(1,838,957)	47,487,806	-2582.3%	----------	NOT APPLICABLE	----------	

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: December 2015

	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)	42,262,094	292,751	41,969,343	14336.2%	----------	NOT APPLICABLE	----------	
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	45,638,740	(1,838,810)	47,477,550	-2582.0%	----------	NOT APPLICABLE	----------	
3. TOTAL BEG. & END. TRUE-UP AMOUNT	87,900,834	(1,546,059)	89,446,893	-5785.5%	----------	NOT APPLICABLE	----------	
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	43,950,417	(773,030)	44,723,447	-5785.5%	----------	NOT APPLICABLE	----------	
5. INT. RATE-FIRST DAY REP. BUS. MONTH	0.150	0.230	(0.080)	-34.8%	----------	NOT APPLICABLE	----------	
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	0.400	0.230	0.170	73.9%	----------	NOT APPLICABLE	----------	
7. TOTAL (LINE D5 + LINE D6)	0.550	0.460	0.090	19.6%	----------	NOT APPLICABLE	----------	
8. AVERAGE INT. RATE (50% OF LINE D7)	0.275	0.230	0.045	19.6%	----------	NOT APPLICABLE	----------	
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.023	0.019	0.004	21.1%	----------	NOT APPLICABLE	----------	
10. INT. PROVISION (LINE D4 x LINE D9)	10,109	(147)	10,256	-6976.9%	----------	NOT APPLICABLE	----------	

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A6

JANUARY 2015 - DECEMBER 2015

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2015 THROUGH DECEMBER 2015

(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	10,330.0	0.0	10,330.0	3.116	3.318	321,850.00	342,726.00	20,876.00
VARIOUS	JURISD.	MKT.BASE	178,480.0	0.0	178,480.0	3.163	3.479	5,644,499.13	6,209,570.00	561,056.87
TOTAL			**188,810.0**	**0.0**	**188,810.0**	**3.160**	**3.470**	**5,966,349.13**	**6,552,296.00**	**581,932.87**
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISD.	SCH. - D	5,364.1	8.3	5,355.8	2.256	2.481	120,806.67	132,858.50	5,284.15
FLORIDA POWER & LIGHT		SCH. - C	25.0	0.0	25.0	2.741	3.177	685.25	794.21	87.71
REEDY CREEK		SCH. - C	28.0	0.0	28.0	2.217	2.814	620.66	787.87	118.82
ORLANDO UTILITIES COMMISSION		SCH. - C	49.0	0.0	49.0	1.264	1.831	619.36	897.19	161.21
THE ENERGY AUTHORITY		SCH. - C	0.0	0.0	0.0	0.000	0.000	0.00	40.54	40.54
CITY OF HOMESTEAD		SCH. - C	10.0	0.0	10.0	1.958	2.963	195.78	296.29	72.91
PROGRESS ENERGY FLORIDA		SCH. - CB	2,491.0	0.0	2,491.0	4.007	5.146	99,826.47	128,189.59	23,923.07
FLORIDA POWER & LIGHT		SCH. - CB	5,475.0	0.0	5,475.0	3.143	3.578	172,073.82	195,900.63	17,717.81
REEDY CREEK		SCH. - CB	58,942.0	0.0	58,942.0	2.395	2.916	1,411,479.59	1,718,696.74	143,700.73
ORLANDO UTILITIES COMMISSION		SCH. - CB	3,236.0	0.0	3,236.0	2.493	2.984	80,670.94	96,548.60	8,418.38
SEMINOLE ELECTRIC		SCH. - CB	9,613.0	0.0	9,613.0	1.944	2.384	186,848.82	229,216.82	19,389.71
THE ENERGY AUTHORITY		SCH. - CB	71.0	0.0	71.0	1.774	2.111	1,259.54	1,499.13	136.64
CITY OF LAKELAND		SCH. - CB	200.0	0.0	200.0	3.046	3.562	6,092.47	7,124.12	647.65
CARGILL ALLIANT		SCH. - MA	787.0	0.0	787.0	2.284	3.293	17,971.16	25,917.36	5,708.29
EXGEN		SCH. - MA	6,527.0	0.0	6,527.0	1.828	2.882	119,343.86	188,079.35	51,370.37
NEW SMYRNA BEACH		SCH. - MA	2,907.0	0.0	2,907.0	2.413	3.353	70,146.26	97,466.05	21,217.15
REEDY CREEK		SCH. - MA	1,133.0	0.0	1,133.0	2.740	2.983	31,039.00	33,798.00	2,759.00
SOUTHERN COMPANY		SCH. - MA	2,534.0	0.0	2,534.0	1.909	2.819	48,371.63	71,420.93	15,796.72
THE ENERGY AUTHORITY		SCH. - MA	9,641.0	0.0	9,641.0	1.971	2.879	190,022.46	277,612.43	62,705.49
EDF TRADING		SCH. - MA	2,405.0	0.0	2,405.0	3.206	6.919	77,101.21	166,413.38	84,051.71
JP MORGAN VENTURES		SCH. - MA	1,991.0	0.0	1,991.0	2.721	4.185	54,165.37	83,318.81	24,086.67
MORGAN STANLEY		SCH. - MA	1,487.0	0.0	1,487.0	1.779	2.584	26,449.11	38,429.09	8,047.97
RAINBOW ENERGY		SCH. - MA	360.0	0.0	360.0	3.025	3.300	10,890.00	11,880.00	990.00
CITY OF HOMESTEAD		SCH. - MA	10.0	0.0	10.0	2.795	7.000	279.50	699.98	417.48
LESS 20% - THRESHOLD EXCESS	*	SCH. - C								(40.54)
SUB-TOTAL			**115,286.1**	**8.3**	**115,277.8**	**2.366**	**3.043**	**2,726,958.93**	**3,507,885.61**	**496,809.64**
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			5,364.1	8.3	5,355.8	2.256	2.481	120,806.67	132,858.50	5,284.15
SUB-TOTAL SCHEDULE C POWER SALES			112.0	0.0	112.0	1.894	2.514	2,121.05	2,816.10	440.65
SUB-TOTAL SCHEDULE CB POWER SALES			80,028.0	0.0	80,028.0	2.447	2.970	1,958,251.65	2,377,175.63	213,933.99
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			29,782.0	0.0	29,782.0	2.168	3.341	645,779.56	995,035.38	277,150.85
TOTAL			**115,286.1**	**8.3**	**115,277.8**	**2.366**	**3.043**	**2,726,958.93**	**3,507,885.61**	**496,809.64**
DIFFERENCE			(73,523.9)	8.3	(73,532.2)	(0.794)	(0.427)	(3,239,390.20)	(3,044,410.39)	(85,123.23)
DIFFERENCE %			-38.9%	0.0%	-38.9%	-25.1%	-12.3%	-54.3%	-46.5%	-14.6%

* Adjustment related to May 2014

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A7

JANUARY 2015 - DECEMBER 2015

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2015 THROUGH DECEMBER 2015

(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:								
OLEANDER	SCH. - D	17,320.0	0.0	0.0	17,320.0	5.951	5.951	1,030,700.00
CALPINE	SCH. - D	12,560.0	0.0	0.0	12,560.0	6.465	6.465	812,050.00
PASCO COGEN	SCH. - D	124,580.0	0.0	0.0	124,580.0	3.987	3.987	4,967,420.00
TOTAL		**154,460.0**	**0.0**	**0.0**	**154,460.0**	**4.409**	**4.409**	**6,810,170.00**
ACTUAL:								
CALPINE	SCH. - D	47,483.0	0.0	0.0	47,483.0	5.070	5.070	2,407,200.01
PASCO COGEN	SCH. - D	293,455.0	0.0	0.0	293,455.0	3.851	3.851	11,300,021.12
OLEANDER	SCH. - D	96,601.0	0.0	0.0	96,601.0	5.111	5.111	4,937,027.94
DUKE	OATT	1,790.0	0.0	0.0	1,790.0	3.071	3.071	54,963.57
CALPINE TECM/OSPREY	OATT	11,133.0	0.0	0.0	11,133.0	3.119	3.119	347,206.22
SUB-TOTAL		**450,462.0**	**0.0**	**0.0**	**450,462.0**	**4.228**	**4.228**	**19,046,418.86**
SUB-TOTAL SCHEDULE D PURCHASED POWER		437,539.0	0.0	0.0	437,539.0	4.261	4.261	18,644,249.07
SUB-TOTAL SCHEDULE OATT PURCHASED POWER		12,923.0	0.0	0.0	12,923.0	3.112	3.112	402,169.79
TOTAL		**450,462.0**	**0.0**	**0.0**	**450,462.0**	**4.228**	**4.228**	**19,046,418.86**
DIFFERENCE		296,002.0	0.0	0.0	296,002.0	(0.181)	(0.181)	12,236,248.86
DIFFERENCE %		191.6%	0.0%	0.0%	191.6%	-4.1%	-4.1%	179.7%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A8

JANUARY 2015 - DECEMBER 2015

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ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2015 THROUGH DECEMBER 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
						CENTS/KWH		
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FROM OTHER UTILITIES	MWH FOR INTER-RUPTIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	**COGEN.**							
	FIRM	72,770.0	0.0	0.0	72,770.0	3.010	3.010	2,190,110.00
	AS AVAIL.	183,370.0	0.0	0.0	183,370.0	3.299	3.299	6,048,790.00
TOTAL		**256,140.0**	**0.0**	**0.0**	**256,140.0**	**3.217**	**3.217**	**8,238,900.00**
ACTUAL:								
	FIRM							
ORANGE COGENERATION L.P.	COGEN.	66,374.0	0.0	0.0	66,374.0	2.479	2.479	1,645,397.40
	AS AVAILABLE							
McKAY BAY REFUSE	COGEN.	5,530.0	0.0	0.0	5,530.0	2.979	2.979	164,758.25
CARGILL RIDGEWOOD	COGEN.	33,050.9	0.0	0.0	33,050.9	2.569	2.569	849,043.73
CARGILL MILLPOINT	COGEN.	40,338.0	0.0	0.0	40,338.0	2.508	2.508	1,011,500.64
CF INDUSTRIES INC.	COGEN.	10,446.0	0.0	0.0	10,446.0	2.594	2.594	270,965.04
IMC-AGRICO-NEW WALES	COGEN.	17,284.0	0.0	0.0	17,284.0	2.612	2.612	451,409.35
IMC-AGRICO-S. PIERCE	COGEN.	167,686.0	0.0	0.0	167,686.0	2.543	2.543	4,263,456.94
HILLSBOROUGH COUNTY	COGEN.	20.0	0.0	0.0	20.0	2.540	2.540	507.95
SUB-TOTAL		**340,728.9**	**0.0**	**0.0**	**340,728.9**	**2.541**	**2.541**	**8,657,039.30**
SUB-TOTAL FOR FIRM		66,374.0	0.0	0.0	66,374.0	2.479	2.479	1,645,397.40
SUB-TOTAL FOR AS AVAIL.		274,354.9	0.0	0.0	274,354.9	2.556	2.556	7,011,641.90
TOTAL		**340,728.9**	**0.0**	**0.0**	**340,728.9**	**2.541**	**2.541**	**8,657,039.30**
DIFFERENCE		84,588.9	0.0	0.0	84,588.9	(0.676)	(0.676)	418,139.30
DIFFERENCE %		33.0%	0.0%	0.0%	33.0%	-21.0%	-21.0%	5.1%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A9

JANUARY 2015 - DECEMBER 2015

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2015 THROUGH DECEMBER 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) COST IF GENERATED		(9)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	TRANSACTION COSTS	TOTAL $ FOR FUEL ADJUSTMENT (5) X (6)	(A) CENTS PER KWH	(B) TOTAL COST	FUEL SAVINGS (8B)-7
ESTIMATED:									
VARIOUS	Economy	509,460.0	0.0	509,460.0	3.335	16,990,090.00	5.449	27,762,653.00	10,772,563.00
TOTAL		**509,460.0**	**0.0**	**509,460.0**	**3.335**	**16,990,090.00**	**5.449**	**27,762,653.00**	**10,772,563.00**
ACTUAL:									
OKEELANTA	SCH. - REB	2,642.0	0.0	2,642.0	2.751	72,689.00	3.030	80,060.50	7,371.50
ORLANDO UTIL. COMM.	SCH. - C	270.0	0.0	270.0	2.929	7,909.05	3.566	9,628.18	1,719.13
DUKE/PROGRESS ENERGY FLORIDA	SCH. - J	33,631.0	0.0	33,631.0	6.802	2,287,478.00	6.940	2,334,036.80	46,558.80
FLA. POWER & LIGHT	SCH. - J	188,784.0	388.7	188,395.3	3.325	6,265,064.18	3.739	7,044,017.36	778,953.18
CITY OF LAKELAND	SCH. - J	2,703.0	0.0	2,703.0	6.718	181,600.00	6.718	181,600.00	0.00
ORLANDO UTIL. COMM.	SCH. - J	21,774.0	0.0	21,774.0	4.503	980,556.00	4.842	1,054,345.14	73,789.14
THE ENERGY AUTHORITY	SCH. - J	23,929.0	45.0	23,884.0	4.634	1,106,722.50	4.798	1,145,986.11	39,263.61
CARGILL ALLIANT	SCH. - J	6,991.0	0.0	6,991.0	5.315	371,563.00	5.507	384,981.86	13,418.86
REEDY CREEK	SCH. - J	405.0	0.0	405.0	6.000	24,300.00	6.031	24,427.40	127.40
SEMINOLE ELEC. CO-OP	SCH. - J	49,305.0	450.4	48,854.6	5.545	2,709,051.00	5.717	2,792,795.80	83,744.80
J P MORGAN VENTURES	SCH. - J	1,687.0	0.0	1,687.0	2.504	42,247.00	3.186	53,746.60	11,499.60
MORGAN STANLEY	SCH. - J	4,439.0	0.0	4,439.0	3.188	141,521.00	3.923	174,121.68	32,600.68
EDF TRADING	SCH. - J	8,161.0	0.0	8,161.0	3.689	301,038.00	4.661	380,361.54	79,323.54
EXGEN	SCH. - J	48,156.0	129.6	48,026.4	3.443	1,653,333.30	4.138	1,987,222.63	333,889.33
SOUTHERN COMPANY	SCH. - J	29,224.0	70.4	29,153.6	3.718	1,083,790.84	4.209	1,227,189.45	143,398.61
RAINBOW ENERGY MARKETERS	SCH. - J	2,942.0	0.0	2,942.0	4.324	127,222.00	4.707	138,482.05	11,260.05
SUB-TOTAL		**425,043.0**	**1,084.1**	**423,958.9**	**4.094**	**17,356,084.87**	**4.485**	**19,013,003.10**	**1,656,918.23**
SUB-TOTAL SCHEDULE REB ECONOMY PURCHASES		2,642.0	0.0	2,642.0	2.751	72,689.00	3.030	80,060.50	7,371.50
SUB-TOTAL SCHEDULE C ECONOMY PURCHASES		270.0	0.0	270.0	2.929	7,909.05	3.566	9,628.18	1,719.13
SUB-TOTAL SCHEDULE J ECONOMY PURCHASES		422,131.0	1,084.1	421,046.9	4.103	17,275,486.82	4.494	18,923,314.42	1,647,827.60
TOTAL		**425,043.0**	**1,084.1**	**423,958.9**	**4.094**	**17,356,084.87**	**4.485**	**19,013,003.10**	**1,656,918.23**
DIFFERENCE		(84,417.0)	1,084.1	(85,501.1)	0.759	365,994.87	(0.965)	(8,749,649.90)	(9,115,644.77)
DIFFERENCE %		-16.6%	0.0%	-16.8%	22.8%	2.2%	-17.7%	-31.5%	-84.6%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A12

JANUARY 2015 - DECEMBER 2015

REDACTED

CAPACITY COSTS
ACTUAL PURCHASES AND SALES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2015 THROUGH DECEMBER 2015

CONTRACT	TERM START	TERM END	CONTRACT TYPE	
ORANGE COGEN LP	4/17/1989	12/31/2015	QF	**QF = QUALIFYING FACILITY**
CALPINE	11/1/2011	12/31/2016	LT	**LT = LONG TERM**
PASCO COGEN LTD	1/1/2009	12/31/2018	LT	**ST = SHORT-TERM**
OLEANDER	1/1/2013	12/31/2015	LT	**** THREE YEAR NOTICE REQUIRED FOR TERMINATION.**
SEMINOLE ELECTRIC **	6/1/1992	----------		

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
ORANGE COGEN LP	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
CALPINE	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
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
OLEANDER	159.0	159.0	159.0	159.0	159.0	159.0	159.0	159.0	157.0	157.0	157.0	157.0
SEMINOLE ELECTRIC	0.4	0.8	1.2	0.8	1.3	0.8	1.0	1.2	1.2	1.5	0.7	0.8

CAPACITY	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
ORANGE COGEN LP	1,261,780	1,261,780	1,261,780	1,261,780	1,261,780	1,261,780	1,261,780	1,261,780	1,261,780	1,261,780	1,261,780	1,261,780	15,141,360
TOTAL COGENERATION	**$ 1,261,780**	**$ 1,261,780**	**$ 1,261,780**	**$ 1,261,780**	**$ 1,261,780**	**$ 1,261,780**	**$ 1,261,780**	**$ 1,261,780**	**$ 1,261,780**	**1,261,780**	**$ 1,261,780**	**$ 1,261,780**	**$ 15,141,360**

REDACTED

CAPACITY COSTS
ACTUAL PURCHASES AND SALES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2015 THROUGH DECEMBER 2015

CAPACITY	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
CALPINE - D	[redacted]												
OLEANDER - D													
PASCO COGEN LTD - D													
CITY OF TALLAHASSEE													
ORLANDO UTILITIES													
FLORIDA POWER & LIGHT													
PROGRESS ENERGY FLORIDA													
JACKSONVILLE ELECTRIC AUTHORITY													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
PROGRESS ENERGY FLORIDA - CB													
FLORIDA POWER & LIGHT - CB													
ORLANDO UTILITIES - CB													
REEDY CREEK - CB													
SEMINOLE ELECTRIC - CB													
THE ENERGY AUTHORITY - CB													
CITY OF LAKELAND - CB													
CARGILL ALLIANT - MA													
EXGEN - MA													
THE ENERGY AUTHORITY - MA													
J P MORGAN VENTURES - MA													
MORGAN STANLEY - MA													
SOUTHERN CO - MA													
NEW SMYRNA BEACH - MA													
EDF TRADING - MA													
CITY OF HOMESTEAD - MA													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	**$ 1,329,184**	**$ 1,355,033**	**$ 1,413,422**	**$ 1,319,301**	**$ 1,586,293**	**$ 1,593,468**	**$ 1,631,931**	**$ 1,645,167**	**$ 1,648,399**	**1,582,730**	**$ 1,557,076**	**$ 1,221,417**	**$ 17,883,421**
TOTAL CAPACITY	**$ 2,590,964**	**$ 2,616,813**	**$ 2,675,202**	**$ 2,581,081**	**$ 2,848,073**	**$ 2,855,248**	**$ 2,893,711**	**$ 2,906,947**	**$ 2,910,179**	**2,844,510**	**$ 2,818,856**	**$ 2,483,197**	**$ 33,024,781**

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 5

CAPITAL PROJECTS APPROVED FOR FUEL CLAUSE RECOVERY

JANUARY 2015 – DECEMBER 2015

POLK UNIT 1 IGNITION CONVERSION TO NATURAL GAS
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2015 THROUGH DECEMBER 2015

		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	$ 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	$ 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	$ 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%	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	269,225	269,225	269,225	269,225	269,225	269,225	3,230,701
10	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
11	BEGINNING BALANCE DEPRECIATION	4,836,498	5,105,723	5,374,948	5,644,173	5,913,398	6,182,623	6,451,848	6,721,073	6,990,298	7,259,523	7,528,748	7,797,974	4,836,498
12	ENDING BALANCE DEPRECIATION	5,105,723	5,374,948	5,644,173	5,913,398	6,182,623	6,451,848	6,721,073	6,990,298	7,259,523	7,528,748	7,797,974	8,067,199	8,067,199
13														
14														
15	ENDING NET INVESTMENT	11,038,228	10,769,003	10,499,778	10,230,553	9,961,328	9,692,102	9,422,877	9,153,652	8,884,427	8,615,202	8,345,977	8,076,752	8,076,752
16														
17														
18	AVERAGE INVESTMENT	11,172,840	10,903,615	10,634,390	10,365,165	10,095,940	9,826,715	9,557,490	9,288,265	9,019,040	8,749,815	8,480,590	8,211,365	
19	ALLOWED EQUITY RETURN	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	.36016%	.36016%	.36016%	.36016%	.36016%	.36016%	
20	EQUITY COMPONENT AFTER-TAX	40,412	39,438	38,465	37,491	36,517	35,543	34,422	33,453	32,483	31,513	30,544	29,574	419,855
21	CONVERSION TO PRE-TAX	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	
22	EQUITY COMPONENT PRE-TAX	65,960	64,371	62,783	61,193	59,603	58,013	56,184	54,602	53,019	51,436	49,854	48,271	685,289
23														
24	ALLOWED DEBT RETURN	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16226%	.16226%	.16226%	.16226%	.16226%	.16226%	
25	DEBT COMPONENT	18,941	18,484	18,028	17,572	17,115	16,659	15,508	15,071	14,634	14,197	13,760	13,323	193,292
26														
27	TOTAL RETURN REQUIREMENTS	84,901	82,855	80,811	78,765	76,718	74,672	71,692	69,673	67,653	65,633	63,614	61,594	878,581
28														
29	TOTAL DEPRECIATION & RETURN	354,126	352,080	350,036	347,990	345,943	343,897	340,917	338,898	336,878	334,858	332,839	330,819	4,109,281
30														
31	ESTIMATED FUEL SAVINGS	250,611	455,980	4,292,824	46,865	18,753,158	25,804,431	1,780,714	1,174,504	2,484,993	1,333,890	4,178,612	1,262,972	61,819,554
32	RECOVERABLE TOTAL DEPRECIATION & RETURN	354,126	352,080	350,036	347,990	345,943	343,897	340,917	338,898	336,878	334,858	332,839	330,819	4,109,281
33	NET BENEFIT (COST) TO RATEPAYER	(103,515)	103,899	3,942,788	(301,125)	18,407,215	25,460,534	1,439,796	835,606	2,148,115	999,032	3,845,773	932,153	57,710,273
34														

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 9.1187% (EQUITY 7.0844% , DEBT 2.0343%). RATES ARE BASED ON THE MAY SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
37 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JULY - DECEMBER USING AN ANNUAL RATE OF 9.0013% (EQUITY 7.0542% , DEBT 1.9471%). RATES ARE BASED ON THE MAY SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
38 RETURN REQUIREMENT IS BASED UPON A COMBINED STATUTORY RATE OF 38.575%.

BIG BEND UNITS 1-4 IGNITERS CONVERSION TO NATURAL GAS
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2015 THROUGH DECEMBER 2015

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1	BEGINNING BALANCE	$0	$14,085,885	$15,274,305	$17,147,160	$9,390,684	12,814,061	$16,344,145	$16,439,823	$16,446,415	$16,465,473	$16,475,422	$20,744,838	$0
2	ADD INVESTMENT: Big Bend Unit 3 (Jan 2015)	14,085,885	1,188,420	1,872,855	830,383	20,565	32,702	10,663	-	4,343	8,074	-	(13)	18,053,877
2a	ADD INVESTMENT: Big Bend Unit 4 (May 2015)					3,400,106	65,656	45,414	2,183	1,541	672	2,206	1,199	3,518,977
2b	ADD INVESTMENT: Big Bend Unit 2 (June 2015)						4,178,371	39,601	4,408	13,175	1,197	8,716	(27,557)	4,217,911
2c	ADD INVESTMENT: Big Bend Unit 1 (November 2015)											4,255,211	104,501	4,359,712
3	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
4	ENDING BALANCE	14,085,885	15,274,305	17,147,160	17,977,543	12,811,356	17,090,790	16,439,823	16,446,415	16,465,473	16,475,416	20,741,555	20,822,967	30,150,477
5														
6														
7	AVERAGE BALANCE	-	14,680,095	16,210,732	17,562,351	9,400,967	12,863,240	16,391,984	16,443,119	16,455,944	16,470,445	16,480,883	20,783,903	
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	-	244,668	270,179	292,706	(188,564)	214,387	273,200	274,052	274,266	274,507	274,681	346,398	2,550,481
10	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
11	BEGINNING BALANCE DEPRECIATION	-	-	244,668	514,847	462,306	618,989	833,377	1,106,577	1,380,629	1,654,894	1,929,402	2,204,083	-
12	ENDING BALANCE DEPRECIATION	-	244,668	514,847	807,553	618,989	833,377	1,106,577	1,380,629	1,654,894	1,929,402	2,204,083	2,550,481	2,550,481
13														
14														
15	ENDING NET INVESTMENT	14,085,885	15,029,637	16,632,313	17,169,990	12,192,367	16,257,413	15,333,247	15,065,786	14,810,579	14,546,015	18,537,472	18,272,486	27,599,996
16														
17														
18	AVERAGE INVESTMENT	$7,042,942	$14,557,761	$15,830,975	$16,901,151	$10,560,373	$14,226,242	$15,422,008	$15,199,516	$14,938,183	$14,678,297	$16,541,746	$18,406,620	
19	ALLOWED EQUITY RETURN	.36170%	.36170%	.36170%	.36170%	.36170%	.36170%	.36016%	.36016%	.36016%	.36016%	.36016%	.36016%	
20	EQUITY COMPONENT AFTER-TAX	25,474	52,655	57,261	61,131	38,197	51,456	55,544	54,743	53,801	52,865	59,577	66,293	628,997
21	CONVERSION TO PRE-TAX	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	
22	EQUITY COMPONENT PRE-TAX	$41,579	$85,943	$93,461	$99,778	($72,172)	$83,986	$90,659	$89,352	$87,814	$86,286	$97,242	$108,203	$892,131
23														
24	ALLOWED DEBT RETURN	.16953%	.16953%	.16953%	.16953%	.16953%	.16953%	.16226%	.16226%	.16226%	.16226%	.16226%	.16226%	
25	DEBT COMPONENT	$11,940	$24,679	$26,837	$28,652	($20,726)	$24,117	$25,023	$24,662	$24,238	$23,816	$26,840	$29,866	$249,944
26														
27	TOTAL RETURN REQUIREMENTS	$53,519	$110,622	$120,298	$128,430	($92,898)	$108,103	$115,682	$114,014	$112,052	$110,102	$124,082	$138,069	$1,142,075
28	PRIOR MONTH TRUE-UP	($80)	47	(138)	171		12	(2,836)	-			0	12	(2,812)
29	TOTAL DEPRECIATION & RETURN	$53,439	$355,337	$390,339	$421,307	($281,462)	$322,502	$386,046	$388,066	$386,318	$384,609	$398,763	$484,479	$3,689,743
30														
31	ESTIMATED FUEL SAVINGS	$32,065	$839,040	$0	$273,561	$779,847	$413,517	$883,626	$3,153,195	$2,482,908	$673,328	$2,849,280	$778,305	$13,158,672
32	RECOVERABLE TOTAL DEPRECIATION & RETURN	$53,439	$355,337	$390,339	$421,307	($281,462)	$322,502	$386,046	$388,066	$386,318	$384,609	$398,763	$484,479	$3,689,743
33	NET BENEFIT (COST) TO RATEPAYER	($21,374)	$483,703	($390,339)	($147,745)	$1,061,309	$91,015	$497,580	$2,765,129	$2,096,590	$288,718	$2,450,517	$293,826	$9,468,929

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 9.1187% (EQUITY 7.0844% , DEBT 2.0343%). RATES ARE BASED ON THE MAY 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 9.0013% (EQUITY 7.0542% , DEBT 1.9471%). RATES ARE BASED ON THE MAY SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
37 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 38.575%
38 ZERO 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 2015 to June 2015

	(1) Jurisdictional Rate Base Actual May 2014 Capital Structure ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,429,551	35.37%	5.55%	1.9630%
Short Term Debt	25,222	0.62%	0.61%	0.0038%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	107,785	2.67%	2.25%	0.0601%
Common Equity	1,707,776	42.26%	10.25%	4.3317%
Deferred ITC - Weighted Cost	8,027	0.20%	8.05%	0.0161%
Accumulated Deferred Income Taxes & Zero Cost ITCs	763,143	18.88%	0.00%	0.0000%
Total	$ 4,041,504	100.00%		6.37%

ITC split between Debt and Equity:

Long Term Debt	$ 1,429,551	Long Term Debt	45.20%
Short Term Debt	25,222	Short Term Debt	0.80%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	1,707,776	Equity - Common	54.00%
Total	$ 3,162,549	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = .0161% * 46.00%	0.0074%
Equity = .0161% * 54.00%	0.0087%
Weighted Cost	0.0161%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.3317%
Deferred ITC - Weighted Cost	0.0087%
	4.3404%
Times Tax Multiplier	1.632200
Total Equity Component	**7.0844%**

Total Debt Cost Rate:

Long Term Debt	1.9630%
Short Term Debt	0.0038%
Customer Deposits	0.0601%
Deferred ITC - Weighted Cost	0.0074%
Total Debt Component	**2.0343%**
	9.1187%

Notes:

Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (4) - Column (2) x Column (3)

Tampa Electric Company
Calculation of Revenue Requirement Rate of Return
For Cost Recovery Clauses
July 2015 to December 2015

	(1) Jurisdictional Rate Base Actual May 2015 Capital Structure ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,500,445	35.24%	5.33%	1.8783%
Short Term Debt	25,918	0.61%	0.71%	0.0043%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	108,557	2.55%	2.27%	0.0579%
Common Equity	1,791,818	42.09%	10.25%	4.3142%
Deferred ITC - Weighted Cost	7,573	0.18%	7.96%	0.0143%
Accumulated Deferred Income Taxes & Zero Cost ITCs	823,006	19.33%	0.00%	0.0000%
Total	$ 4,257,317	100.00%		6.27%

ITC split between Debt and Equity:

Long Term Debt	$ 1,500,445	Long Term Debt	45.22%
Short Term Debt	25,918	Short Term Debt	0.78%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	1,791,818	Equity - Common	54.00%
Total	$ 3,318,181	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = .0161% * 46.00%	0.0066%
Equity = .0161% * 54.00%	0.0077%
Weighted Cost	0.0143%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.3142%
Deferred ITC - Weighted Cost	0.0077%
	4.3219%
Times Tax Multiplier	1.632200
Total Equity Component	7.0542%

Total Debt Cost Rate:

Long Term Debt	1.8783%
Short Term Debt	0.0043%
Customer Deposits	0.0579%
Deferred ITC - Weighted Cost	0.0066%
Total Debt Component	1.9471%
	9.0013%

Notes:

Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
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 2016 THROUGH DECEMBER 2016

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 50
PARTY: TAMPA ELECTRIC COMPANY – (DIRECT)
DESCRIPTION: Penelope A. Rusk PAR-2

TAMPA ELECTRIC COMPANY

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3	Schedule E2 Cost Recovery Clause Calculation	(")
4-5	Schedule E3 Generating System Comparative Data	(")
6-17	Schedule E4 System Net Generation and Fuel Cost	(")
18-19	Schedule E5 Inventory Analysis	(")
20-21	Schedule E6 Power Sold	(")
22-23	Schedule E7 Purchased Power	(")
24	Schedule E8 Energy Payment to Qualifying Facilities	(")
25	Schedule E9 Economy Energy Purchases	(")

TAMPA ELECTRIC COMPANY
CALCULATION OF ESTIMATED TRUE-UP
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2016 THROUGH DECEMBER 2016

SCHEDULE E1-B

		ACTUAL						ESTIMATED						
		Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	TOTAL
A. 1.	Fuel Cost of System Net Generation	43,911,504	37,828,036	38,162,586	38,997,539	51,595,289	52,186,421	59,355,953	55,466,586	49,337,895	49,382,032	34,877,852	41,017,617	552,119,310
2.	Fuel Cost of Power Sold (1)	772,750	178,465	149,075	239,475	140,843	85,065	58,037	60,876	53,882	46,781	44,461	42,625	1,872,335
3.	Fuel Cost of Purchased Power	1,024,587	3,044,319	2,858,374	2,551,581	5,510,678	7,259,443	7,517,200	6,785,540	5,911,060	2,905,590	2,012,000	883,620	48,263,992
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	377,381	367,240	467,423	566,879	445,937	412,546	350,710	188,720	163,740	142,640	175,110	133,840	3,792,166
4.	Energy Cost of Economy Purchases	235,532	71,820	159,720	387,642	367,914	529,448	828,180	914,820	708,960	719,370	746,570	802,800	6,472,776
5.	Adj. Big Bend Units 1-4 Igniters Conversion Project	483,807	482,190	479,622	477,068	474,468	471,854	468,174	465,584	462,992	460,401	457,809	455,218	5,639,187
5a.	Adj. Polk 1 Ignition Conversion	328,799	326,781	350,036	297,465	320,722	318,702	316,263	314,263	312,262	310,260	308,258	306,257	3,810,068
5b.	Adj. Polk Warm Gas Cleanup	(97,988)	(91,513)	0	(223,022)	(65,890)	0	0	0	0	0	0	0	(478,413)
6.	**TOTAL FUEL & NET POWER TRANS.**	**45,490,872**	**41,850,408**	**42,328,686**	**42,815,677**	**58,508,275**	**61,093,349**	**68,778,443**	**64,074,637**	**56,843,027**	**53,873,512**	**38,533,138**	**43,556,727**	**617,746,751**
(1)	Includes Gains													
B. 1.	Jurisdictional MWH Sales	1,507,012	1,359,534	1,298,063	1,411,115	1,520,108	1,800,205	1,851,022	1,853,811	1,904,945	1,679,910	1,408,899	1,391,834	18,986,458
2.	Non-Jurisdictional MWH Sales	0	0	765	900	402	1,811	3,010	2,970	2,060	280	0	240	12,438
3.	**TOTAL SALES (LINE B1+B2)**	**1,507,012**	**1,359,534**	**1,298,828**	**1,412,015**	**1,520,510**	**1,802,016**	**1,854,032**	**1,856,781**	**1,907,005**	**1,680,190**	**1,408,899**	**1,392,074**	**18,998,896**
4.	**Jurisdictional % of Total Sales**	**1.0000000**	**1.0000000**	**0.9995379**	**0.9994432**	**0.9998203**	**0.9989962**	**0.9988451**	**0.9987408**	**0.9990011**	**0.9998526**	**1.0000000**	**0.9998186**	**-**
C. 1.	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	54,861,280	49,241,664	46,763,520	51,060,014	55,429,679	66,591,818	68,697,387	68,787,117	70,756,513	61,714,705	51,062,699	50,325,258	695,291,654
1a.	Adjustment to Fuel Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
2.	True-up Provision	2,299,213	2,299,213	2,299,213	2,299,213	2,299,213	2,299,213	2,299,213	2,299,213	2,299,213	2,299,213	2,299,213	2,299,207	27,590,550
2a.	Incentive Provision	(104,883)	(104,883)	(104,883)	(104,883)	(104,883)	(104,883)	(104,883)	(104,883)	(104,883)	(104,883)	(104,883)	(104,887)	(1,258,600)
3.	**FUEL REVENUE APPLICABLE TO PERIOD**	**57,055,610**	**51,435,994**	**48,957,850**	**53,254,344**	**57,624,009**	**68,786,148**	**70,891,717**	**70,981,447**	**72,950,843**	**63,909,035**	**53,257,029**	**52,519,578**	**721,623,604**
4.	Total Fuel and Net Power Transactions (Line A6)	45,490,872	41,850,408	42,328,686	42,815,677	58,508,275	61,093,349	68,778,443	64,074,637	56,843,027	53,873,512	38,533,138	43,556,727	617,746,751
5.	Jurisd. Total Fuel and Net Power Transactions (Line A6*Line B4)	45,490,872	41,850,408	42,309,127	42,791,837	58,497,761	61,032,022	68,699,011	63,993,954	56,786,247	53,865,571	38,533,138	43,548,826	617,398,774
5a.	Jurisdictional Loss Multiplier	1.00000	1.00000	1.00018	1.00018	1.00018	1.00018	1.00018	1.00018	1.00018	1.00018	1.00000	1.00018	-
5b.	Jurisdictional Sales Adjusted for Line Losses	45,490,872	41,850,408	42,316,743	42,799,540	58,508,291	61,043,008	68,711,377	64,005,473	56,796,469	53,875,267	38,533,138	43,556,665	617,487,251
5c.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	**JURISD. TOTAL FUEL AND NET POWER TRANSACTIONS**	**45,490,872**	**41,850,408**	**42,316,743**	**42,799,540**	**58,508,291**	**61,043,008**	**68,711,377**	**64,005,473**	**56,796,469**	**53,875,267**	**38,533,138**	**43,556,665**	**617,487,251**
7.	Over/(Under) Recovery	11,564,738	9,585,586	6,641,107	10,454,804	(884,282)	7,743,140	2,180,340	6,975,974	16,154,374	10,033,768	14,723,891	8,962,913	104,136,353
7a.	Prior Months Interest adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Interest Provision	16,593	19,915	23,187	23,324	23,421	25,277	24,650	25,387	43,427	66,641	73,439	79,883	445,144
9.	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD**													**104,581,497**

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2016 THROUGH DECEMBER 2016

SCHEDULE E2

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
		Actual						Estimated						TOTAL
		Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	PERIOD
1.	Fuel Cost of System Net Generation	43,911,504	37,828,036	38,162,586	38,997,539	51,595,289	52,186,421	59,355,953	55,466,586	49,337,895	49,382,032	34,877,852	41,017,617	552,119,310
2.	Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	Fuel Cost of Power Sold [1]	772,750	178,465	149,075	239,475	140,843	85,065	58,037	60,876	53,882	46,781	44,461	42,625	1,872,335
4.	Fuel Cost of Purchased Power	1,024,587	3,044,319	2,858,374	2,551,581	5,510,678	7,259,443	7,517,200	6,785,540	5,911,060	2,905,590	2,012,000	883,620	48,263,992
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	377,381	367,240	467,423	566,879	445,937	412,546	350,710	188,720	163,740	142,640	175,110	133,840	3,792,166
7.	Energy Cost of Economy Purchases	235,532	71,820	159,720	387,642	367,914	529,448	828,180	914,820	708,960	719,370	746,570	802,800	6,472,776
8.	Adj. Big Bend Units 1-4 Igniters Conversion Project	483,807	482,190	479,622	477,068	474,468	471,854	468,174	465,584	462,992	460,401	457,809	455,218	5,639,187
9.	Adj. Polk 1 Ignition Conversion	328,799	326,781	350,036	297,465	320,722	318,702	316,263	314,263	312,262	310,260	308,258	306,257	3,810,068
10.	Adj. Polk Warm Gas Cleanup	(97,988)	(91,513)	0	(223,022)	(65,890)	0	0	0	0	0	0	0	(478,413)
11.	**TOTAL FUEL & NET POWER TRANSACTIONS**	**45,490,872**	**41,850,408**	**42,328,686**	**42,815,677**	**58,508,275**	**61,093,349**	**68,778,443**	**64,074,637**	**56,843,027**	**53,873,512**	**38,533,138**	**43,556,727**	**617,746,751**
12.	Jurisdictional MWH Sold	1,507,012	1,359,534	1,298,063	1,411,115	1,520,108	1,800,205	1,851,022	1,853,811	1,904,945	1,679,910	1,408,899	1,391,834	18,986,458
13.	Jurisdictional % of Total Sales	1.0000000	1.0000000	0.9995379	0.9994432	0.9998203	0.9989962	0.9988451	0.9987408	0.9990011	0.9998526	1.0000000	0.9998186	-
14.	Jurisdictional Total Fuel & Net Power Transactions (Line 11 * Line 13)	45,490,872	41,850,408	42,309,127	42,791,837	58,497,761	61,032,022	68,699,011	63,993,954	56,786,247	53,865,571	38,533,138	43,548,826	617,398,774
15.	Jurisdictional Loss Multiplier	1.00000	1.00000	1.00018	1.00018	1.00018	1.00018	1.00018	1.00018	1.00018	1.00018	1.00000	1.00018	-
16.	Jurisdictional Sales Adjusted for Line Losses (Line 14 * Line 15)	45,490,872	41,850,408	42,316,743	42,799,540	58,508,291	61,043,008	68,711,377	64,005,473	56,796,469	53,875,267	38,533,138	43,556,665	617,487,251
17.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0
18.	**JURISD. TOTAL FUEL & NET PWR. TRANS. (LINE 16+17)**	**45,490,872**	**41,850,408**	**42,316,743**	**42,799,540**	**58,508,291**	**61,043,008**	**68,711,377**	**64,005,473**	**56,796,469**	**53,875,267**	**38,533,138**	**43,556,665**	**617,487,251**
19.	Cost Per kWh Sold (Cents/kWh)	3.0186	3.0783	3.2600	3.0330	3.8490	3.3909	3.7121	3.4526	2.9815	3.2070	2.7350	3.1294	3.2523
20.	True-up (Cents/kWh) [2]	(0.1526)	(0.1691)	(0.1771)	(0.1629)	(0.1513)	(0.1277)	(0.1242)	(0.1240)	(0.1207)	(0.1369)	(0.1632)	(0.1652)	(0.1479)
21.	Total (Cents/kWh) (Line 19+20)	2.8660	2.9092	3.0829	2.8701	3.6977	3.2632	3.5879	3.3286	2.8608	3.0701	2.5718	2.9642	3.1044
22.	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
23.	Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	2.8681	2.9113	3.0851	2.8722	3.7004	3.2655	3.5905	3.3310	2.8629	3.0723	2.5737	2.9663	3.1066
24.	GPIF Adjusted for Taxes (Cents/kWh) [2]	0.0070	0.0077	0.0081	0.0074	0.0069	0.0058	0.0057	0.0057	0.0055	0.0062	0.0074	0.0075	0.0067
25.	**TOTAL RECOVERY FACTOR (LINE 23+24)**	**2.8751**	**2.9190**	**3.0932**	**2.8796**	**3.7073**	**3.2713**	**3.5962**	**3.3367**	**2.8684**	**3.0785**	**2.5811**	**2.9738**	**3.1133**
26.	**RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH**	**2.875**	**2.919**	**3.093**	**2.880**	**3.707**	**3.271**	**3.596**	**3.337**	**2.868**	**3.079**	**2.581**	**2.974**	**3.113**

[1] Includes Gains
[2] Based on Jurisdictional Sales Only

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ACTUAL FOR THE PERIOD: JANUARY 2016 THROUGH JUNE 2016

SCHEDULE E3

	ACTUAL					
	Jan-16	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	8,295	52,885	0	6,639	1,822,960	-1,757
3. COAL	17,634,085	13,721,127	13,363,297	10,323,782	25,882,809	25,822,614
4. NATURAL GAS	26,171,136	23,962,511	24,799,289	28,444,096	23,823,630	26,365,564
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**43,813,516**	**37,736,523**	**38,162,586**	**38,774,517**	**51,529,399**	**52,186,421**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	20	143	0	19	0	0
10. COAL	554,751	364,137	378,729	296,540	637,431	720,961
11. NATURAL GAS	918,394	822,154	901,669	1,080,670	803,220	892,692
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	186	271	287	257	350	292
14. TOTAL (MWH)	**1,473,351**	**1,186,705**	**1,280,685**	**1,377,486**	**1,441,001**	**1,613,945**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	65	415	0	52	0	0
17. COAL (TON)	237,150	157,333	163,665	122,290	288,391	312,703
18. NATURAL GAS (MCF)	6,971,622	6,475,412	7,727,814	8,687,853	5,997,292	7,000,177
19. NUCLEAR (MMBTU)	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	376	2,395	0	301	0	0
23. COAL	5,777,559	3,824,131	4,014,105	2,993,435	6,819,975	7,545,670
24. NATURAL GAS	7,131,969	6,630,822	7,905,554	8,888,882	6,117,238	7,126,182
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**12,909,904**	**10,457,348**	**11,919,659**	**11,882,618**	**12,937,212**	**14,671,852**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.00	0.01	0.00	0.00	0.00	0.00
30. COAL	37.66	30.69	29.57	21.53	44.24	44.67
31. NATURAL GAS	62.33	69.28	70.41	78.45	55.74	55.31
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.01	0.02	0.02	0.02	0.02	0.02
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)	127.62	127.43	0.00	127.67	0.00	0.00
37. COAL ($/TON)	74.36	87.21	81.65	84.42	89.75	82.58
38. NATURAL GAS ($/MCF)	3.75	3.70	3.21	3.27	3.97	3.77
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	22.08	22.08	0.00	22.09	0.00	0.00
43. COAL	3.05	3.59	3.33	3.45	3.80	3.42
44. NATURAL GAS	3.67	3.61	3.14	3.20	3.89	3.70
45. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**3.39**	**3.61**	**3.20**	**3.26**	**3.98**	**3.56**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	18,780	16,746	0	15,821	0	0
50. COAL	10,415	10,502	10,599	10,095	10,699	10,466
51. NATURAL GAS	7,766	8,065	8,768	8,225	7,616	7,983
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**8,762**	**8,812**	**9,307**	**8,626**	**8,978**	**9,091**
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	41.48	36.98	0.00	34.94	0.00	0.00
57. COAL	3.18	3.77	3.53	3.48	4.06	3.58
58. NATURAL GAS	2.85	2.91	2.75	2.63	2.97	2.95
59. NUCLEAR	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)	**2.97**	**3.18**	**2.98**	**2.81**	**3.58**	**3.23**

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE **SCHEDULE E3**
ESTIMATED FOR THE PERIOD: JULY 2016 THROUGH DECEMBER 2016

	Estimated						
	Jul-16	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**TOTAL**
FUEL COST OF SYSTEM NET GENERATION ($)							
1. HEAVY OIL	0	0	0	0	0	0	0
2. LIGHT OIL	50,783	65,671	52,820	50,109	58,613	55,882	2,222,900
3. COAL	30,722,489	31,137,807	25,283,910	22,328,492	19,677,285	23,037,483	258,935,180
4. NATURAL GAS	28,582,681	24,263,108	24,001,165	27,003,431	15,141,954	17,924,252	290,482,817
5. NUCLEAR	0	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0	0
7. TOTAL ($)	**59,355,953**	**55,466,586**	**49,337,895**	**49,382,032**	**34,877,852**	**41,017,617**	**551,640,897**
SYSTEM NET GENERATION (MWH)							
8. HEAVY OIL	0	0	0	0	0	0	0
9. LIGHT OIL	220	280	220	220	250	240	1,612
10. COAL	903,900	898,360	743,550	675,750	616,040	693,160	7,483,309
11. NATURAL GAS	808,420	857,750	889,350	865,050	641,430	732,210	10,213,009
12. NUCLEAR	0	0	0	0	0	0	0
13. OTHER	290	290	260	290	440	410	3,623
14. TOTAL (MWH)	**1,712,830**	**1,756,680**	**1,633,380**	**1,541,310**	**1,258,160**	**1,426,020**	**17,701,553**
UNITS OF FUEL BURNED							
15. HEAVY OIL (BBL)	0	0	0	0	0	0	0
16. LIGHT OIL (BBL)	400	520	420	400	470	450	3,192
17. COAL (TON)	394,810	391,510	322,250	292,380	268,810	299,250	3,250,542
18. NATURAL GAS (MCF)	5,940,860	6,237,980	6,391,620	6,240,420	4,646,670	5,257,800	77,575,520
19. NUCLEAR (MMBTU)	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	2,360	2,960	2,440	2,360	2,740	2,580	18,511
23. COAL	9,400,440	9,327,270	7,720,540	7,009,150	6,388,970	7,194,810	78,016,055
24. NATURAL GAS	6,080,920	6,395,830	6,544,310	6,396,150	4,744,770	5,382,110	79,344,737
25. NUCLEAR	0	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0	0
27. TOTAL (MMBTU)	**15,483,720**	**15,726,060**	**14,267,290**	**13,407,660**	**11,136,480**	**12,579,500**	**157,379,303**
GENERATION MIX (% MWH)							
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.01	0.02	0.01	0.01	0.02	0.02	0.01
30. COAL	52.77	51.13	45.52	43.85	48.97	48.60	42.27
31. NATURAL GAS	47.20	48.83	54.45	56.12	50.98	51.35	57.70
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.02	0.02	0.02	0.02	0.03	0.03	0.02
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)	126.96	126.29	125.76	125.27	124.71	124.18	696.40
37. COAL ($/TON)	77.82	79.53	78.46	76.37	73.20	76.98	79.66
38. NATURAL GAS ($/MCF)	4.81	3.89	3.76	4.33	3.26	3.41	3.74
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)							
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	21.52	22.19	21.65	21.23	21.39	21.66	120.09
43. COAL	3.27	3.34	3.27	3.19	3.08	3.20	3.32
44. NATURAL GAS	4.70	3.79	3.67	4.22	3.19	3.33	3.66
45. NUCLEAR	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)	**3.83**	**3.53**	**3.46**	**3.68**	**3.13**	**3.26**	**3.51**
BTU BURNED PER KWH (BTU/KWH)							
48. HEAVY OIL	0	0	0	0	0	0	0
49. LIGHT OIL	10,727	10,571	11,091	10,727	10,960	10,750	11,483
50. COAL	10,400	10,383	10,383	10,372	10,371	10,380	10,425
51. NATURAL GAS	7,522	7,457	7,359	7,394	7,397	7,351	7,769
52. NUCLEAR	0	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**9,040**	**8,952**	**8,735**	**8,699**	**8,851**	**8,821**	**8,891**
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	23.08	23.45	24.01	22.78	23.45	23.28	137.90
57. COAL	3.40	3.47	3.40	3.30	3.19	3.32	3.46
58. NATURAL GAS	3.54	2.83	2.70	3.12	2.36	2.45	2.84
59. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**3.47**	**3.16**	**3.02**	**3.20**	**2.77**	**2.88**	**3.12**

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: January 2016

SCHEDULE A4
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REVISED 6/20/16

(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**	**186**	**15.6**	**-**	**38.4**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
B.B.#1 NAT GAS CO-FIRE	141	7,437	7.1	48.0	22.8	11,073	NG CO-FIRE	80,499	1,023,000	82,350.0	364,767	4.90	4.53
B.B.#1 COAL	395	74,698	25.4	48.0	51.9	10,870	COAL	33,930	23,930,000	811,941.3	2,569,600	3.44	75.73
BIG BEND #1 TOTAL	**395**	**82,135**	**27.9**	**48.0**	**57.0**	**10,888**	**-**	**-**	**-**	**894,291.3**	**2,934,367**	**3.57**	**-**
B.B.#2 NAT GAS CO-FIRE	141	37,851	36.1	80.0	64.8	11,501	NG CO-FIRE	425,525	1,023,000	435,312.0	1,607,697	4.25	3.78
B.B.#2 COAL	395	101,092	34.4	76.0	43.0	11,237	COAL	47,656	23,836,000	1,135,938.4	3,609,102	3.57	75.73
BIG BEND #2 TOTAL	**395**	**138,943**	**47.3**	**76.7**	**59.1**	**11,309**	**-**	**-**	**-**	**1,571,250.4**	**5,216,799**	**3.75**	**-**
B.B.#3 NAT GAS CO-FIRE	141	9,925	9.5	37.8	46.0	12,074	NG CO-FIRE	117,138	1,023,000	119,832.0	446,255	4.50	3.81
B.B.#3 COAL	400	24,210	8.1	37.8	30.0	11,789	COAL	9,259	23,150,000	213,864.2	701,206	2.90	75.73
BIG BEND #3 TOTAL	**400**	**34,135**	**11.5**	**37.8**	**42.3**	**11,872**	**-**	**-**	**-**	**333,696.2**	**1,147,461**	**3.36**	**-**
B.B.#4 NAT GAS CO-FIRE	163	23,183	19.1	100.0	29.9	10,583	NG CO-FIRE	239,830	1,023,000	245,346.0	904,860	3.90	3.77
B.B.#4 COAL	442	192,678	58.6	91.7	58.6	10,435	COAL	87,430	22,996,000	2,010,540.5	6,621,282	3.44	75.73
BIG BEND #4 TOTAL	**442**	**215,861**	**65.6**	**92.7**	**65.6**	**10,451**	**-**	**-**	**-**	**2,255,886.5**	**7,526,142**	**3.49**	**-**
B.B. IGNITION	-	-	-	-	-	-	GAS	35,434	1,023,000	36,249.0	132,503	-	3.74
BIG BEND 1-4 COAL TOTAL	**1,632**	**392,678**	**32.3**	**64.1**	**49.8**	**10,807**	**COAL**	**178,275**	**23,401,969**	**4,172,284.4**	**13,501,190**	**3.44**	**75.73**
B.B. CT#4 (OIL)	61	0	0.0	99.4	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B. CT#4 (GAS)	61	966	2.1	99.4	84.0	12,349	GAS	11,661	1,023,000	11,929.0	43,605	4.51	3.74
BIG BEND CT #4 TOTAL	**61**	**966**	**2.1**	**99.4**	**84.0**	**12,349**	**-**	**-**	**-**	**11,929.0**	**43,605**	**4.51**	**-**
BIG BEND STATION TOTAL	**1,693**	**472,040**	**37.5**	**65.8**	**59.8**	**10,886**	**-**	**-**	**-**	**5,067,053.4**	**17,000,877**	**3.60**	**-**
POLK #1 GASIFIER	220	162,073	99.0	100.0	99.1	9,905	COAL	58,875	27,265,997	1,605,274.9	4,098,380	2.53	69.61
POLK #1 CT (GAS)	195	2,126	1.5	100.0	16.6	6,183	GAS	12,849	1,023,000	13,145.0	48,056	2.26	3.74
POLK #1 TOTAL	**220**	**164,199**	**100.3**	**100.0**	**100.3**	**9,856**	**-**	**-**	**-**	**1,618,419.9**	**4,146,436**	**2.53**	**-**
POLK #2 CT (GAS)	183	1,813	1.3	99.9	46.0	13,473	GAS	23,878	1,023,000	24,427.0	89,292	4.93	3.74
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	**183**	**1,813**	**1.3**	**99.9**	**46.0**	**13,473**	**-**	**-**	**-**	**24,427.0**	**89,292**	**4.93**	**-**
POLK #3 CT (GAS)	183	455	0.3	74.6	13.8	19,143	GAS	8,514	1,023,000	8,710.0	31,839	7.00	3.74
POLK #3 CT (OIL)	187	20	0.0	74.6	18.4	18,780	LGT.OIL	65	5,772,546	375.6	8,295	41.48	127.62
POLK #3 TOTAL	**183**	**475**	**0.3**	**74.6**	**13.9**	**19,128**	**-**	**-**	**-**	**9,085.6**	**40,134**	**8.45**	**-**
POLK #4 (GAS)	**183**	**2,355**	**1.7**	**100.0**	**66.7**	**12,904**	**GAS**	**29,707**	**1,023,000**	**30,390.0**	**111,092**	**4.72**	**3.74**
POLK #5 (GAS)	**183**	**2,534**	**1.9**	**100.0**	**69.1**	**12,381**	**GAS**	**30,669**	**1,023,000**	**31,374.0**	**114,688**	**4.53**	**3.74**
POLK STATION TOTAL	**952**	**171,376**	**24.2**	**95.1**	**96.2**	**10,000**	**-**	**-**	**-**	**1,713,696.5**	**4,501,642**	**2.63**	**-**
CITY OF TAMPA 1	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
CITY OF TAMPA 2	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
CITY OF TAMPA TOTAL [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
BAYSIDE ST 1	243	126,277	69.8	100.0	69.8	-		-	-	-	-	-	-
BAYSIDE CT1A	183	104,297	76.6	100.0	77.7	11,163	GAS	1,138,117	1,023,000	1,164,293.0	4,256,843	4.08	3.74
BAYSIDE CT1B	183	77,256	56.7	100.0	80.5	11,212	GAS	846,755	1,023,000	866,230.0	3,167,076	4.10	3.74
BAYSIDE CT1C	183	69,436	51.0	100.0	71.4	10,786	GAS	732,113	1,023,000	748,952.0	2,738,286	3.94	3.74
BAYSIDE UNIT 1 TOTAL	**792**	**377,266**	**64.0**	**100.0**	**64.0**	**7,367**	**GAS**	**2,716,985**	**1,023,000**	**2,779,475.0**	**10,162,205**	**2.69**	**3.74**
BAYSIDE ST 2	315	151,725	64.7	100.0	64.7	-		-	-	-	-	-	-
BAYSIDE CT2A	183	85,246	62.6	100.0	77.6	10,956	GAS	912,942	1,023,000	933,940.0	3,414,581	4.01	3.74
BAYSIDE CT2B	183	80,942	59.4	99.6	78.5	11,433	GAS	904,568	1,023,000	925,373.0	3,383,261	4.18	3.74
BAYSIDE CT2C	183	73,943	54.3	100.0	82.2	11,017	GAS	796,337	1,023,000	814,653.0	2,978,455	4.03	3.74
BAYSIDE CT2D	183	57,024	41.9	92.5	74.2	11,137	GAS	620,784	1,023,000	635,062.0	2,321,853	4.07	3.74
BAYSIDE UNIT 2 TOTAL	**1,047**	**448,880**	**57.6**	**98.0**	**57.6**	**7,372**	**GAS**	**3,234,631**	**1,023,000**	**3,309,028.0**	**12,098,150**	**2.70**	**3.74**
BAYSIDE UNIT 3 TOTAL	**61**	**772**	**1.7**	**99.2**	**65.5**	**11,565**	**GAS**	**8,727**	**1,023,000**	**8,928.0**	**32,644**	**4.23**	**3.74**
BAYSIDE UNIT 4 TOTAL	**61**	**2,446**	**5.4**	**99.5**	**94.4**	**10,942**	**GAS**	**26,161**	**1,023,000**	**26,763.0**	**97,851**	**4.00**	**3.74**
BAYSIDE UNIT 5 TOTAL	**61**	**268**	**0.6**	**100.0**	**82.4**	**12,873**	**GAS**	**3,372**	**1,023,000**	**3,450.0**	**12,614**	**4.71**	**3.74**
BAYSIDE UNIT 6 TOTAL	**61**	**117**	**0.3**	**99.5**	**81.0**	**12,906**	**GAS**	**1,476**	**1,023,000**	**1,510.0**	**5,521**	**4.72**	**3.74**
BAYSIDE STATION TOTAL	**2,083**	**829,749**	**53.5**	**99.0**	**60.5**	**7,387**	**GAS**	**5,991,352**	**1,023,000**	**6,129,154.0**	**22,408,985**	**2.70**	**3.74**
SYSTEM	**4,730**	**1,473,351**	**41.9**	**86.3**	**62.9**	**8,811**	**-**	**-**	**-**	**12,909,903.9**	**43,911,504**	**2.98**	**-**

Footnotes:

[1] **As burned fuel cost system total includes ignition and excludes the Polk warm gas cleanup credit.**

[2] **Fuel burned (MM BTU) system total excludes ignition.**

[3] **City of Tampa on Long Term Reserve Stand-by.**

LEGEND:

B.B. = BIG BEND
CT = COMBUSTION TURBINE
NG = NATURAL GAS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: February 2016

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(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**	**271**	**24.3**	**-**	**57.0**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
B.B.#1 NAT GAS CO-FIRE	141	45,455	46.3	77.4	56.6	-	NG CO-FIRE	483,137	1,024,000	494,733.0	1,724,776	3.79	3.57
B.B.#1 COAL	395	111,975	40.7	77.4	49.7	-	COAL	50,848	23,406,000	1,190,140.6	4,440,612	3.97	87.33
BIG BEND #1 TOTAL	**395**	**157,430**	**57.3**	**77.4**	**69.9**	**10,702**	**-**	**-**	**-**	**1,684,873.6**	**6,165,388**	**3.92**	**-**
B.B.#2 NAT GAS CO-FIRE	141	7,230	7.4	8.4	86.2	-	NG CO-FIRE	81,865	1,024,000	83,830.0	292,219	4.04	3.57
B.B.#2 COAL	395	11,305	4.1	8.4	48.1	-	COAL	5,557	22,946,000	127,500.6	485,299	4.29	87.33
BIG BEND #2 TOTAL	**395**	**18,535**	**6.7**	**8.4**	**78.9**	**11,402**	**-**	**-**	**-**	**211,330.6**	**777,518**	**4.19**	**-**
B.B.#3 NAT GAS CO-FIRE	141	21,494	21.9	11.3	96.2	-	NG CO-FIRE	228,878	1,024,000	234,371.0	840,138	3.91	3.67
B.B.#3 COAL [3]	400	0	0.0	0.0	0.0	-	COAL	3,070	0	71,551.9	268,106	0.00	87.33
BIG BEND #3 TOTAL	**400**	**21,494**	**7.7**	**11.3**	**33.9**	**10,904**	**-**	**-**	**-**	**305,922.9**	**1,108,244**	**5.16**	**-**
B.B.#4 NAT GAS CO-FIRE	163	54,176	47.8	73.4	51.2	-	NG CO-FIRE	546,225	1,024,000	559,334.0	2,016,071	3.72	3.69
B.B.#4 COAL	442	124,720	40.5	72.6	43.5	-	COAL	55,677	22,712,000	1,264,561.2	4,862,334	3.90	87.33
BIG BEND #4 TOTAL	**442**	**178,896**	**58.2**	**73.4**	**62.4**	**10,195**	**-**	**-**	**-**	**1,823,895.2**	**6,878,405**	**3.84**	**-**
B.B. IGNITION	-	-	-	-	-	-	GAS	154,263	24,325,857	3,824,131.3	165,818	-	1.07
BIG BEND 1-4 COAL TOTAL	**1,632**	**248,000**	**21.8**	**40.4**	**41.4**	**10,412**	**COAL**	**115,152**	**23,038,443**	**2,653,754.3**	**10,056,351**	**4.05**	**87.33**
B.B. CT#4 (OIL)	61	0	0.0	97.9	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B. CT#4 (GAS)	61	500	1.2	97.9	77.2	13,320	GAS	6,504	1,024,000	6,660.0	24,223	4.84	3.72
BIG BEND CT #4 TOTAL	**61**	**500**	**1.2**	**97.9**	**77.2**	**13,320**	**-**	**-**	**-**	**6,660.0**	**24,223**	**4.84**	**-**
BIG BEND STATION TOTAL	**1,693**	**376,855**	**32.0**	**45.4**	**62.9**	**10,511**	**-**	**-**	**-**	**4,032,682.3**	**15,119,596**	**4.01**	**-**
POLK #1 GASIFIER	220	116,137	75.8	69.7	98.4	10,078	COAL	42,181	27,746,768	1,170,377.0	3,590,471	3.09	85.12
POLK #1 CT (GAS)	195	11,557	8.5	92.3	48.6	8,617	GAS	97,252	1,024,000	99,586.0	359,972	3.11	3.70
POLK #1 TOTAL	**220**	**127,694**	**83.4**	**92.3**	**96.8**	**9,945**	**-**	**-**	**-**	**1,269,963.0**	**3,950,443**	**3.09**	**-**
POLK #2 CT (GAS)	183	376	0.3	85.6	35.7	19,098	GAS	7,013	1,024,000	7,181.0	26,273	6.99	3.75
POLK #2 CT (OIL)	187	32	0.0	85.6	17.3	25,844	LGT.OIL	143	5,772,544	827.0	18,263	57.07	127.71
POLK #2 TOTAL	**183**	**408**	**0.3**	**85.6**	**33.0**	**19,627**	**-**	**-**	**-**	**8,008.0**	**44,536**	**10.92**	**-**
POLK #3 CT (GAS)	183	2,680	2.1	49.3	62.1	12,475	GAS	32,643	1,024,000	33,426.0	120,882	4.51	3.70
POLK #3 CT (OIL)	187	111	0.1	49.3	35.3	14,123	LGT.OIL	272	5,784,899	1,567.7	34,622	31.19	127.29
POLK #3 TOTAL	**183**	**2,791**	**2.2**	**49.3**	**60.4**	**12,538**	**-**	**-**	**-**	**34,993.7**	**155,504**	**5.57**	**-**
POLK #4 (GAS)	**183**	**5,676**	**4.5**	**99.0**	**70.3**	**11,811**	**GAS**	**65,466**	**1,024,000**	**67,037.0**	**242,607**	**4.27**	**3.71**
POLK #5 (GAS)	**183**	**804**	**0.6**	**70.7**	**43.9**	**18,019**	**GAS**	**14,147**	**1,024,000**	**14,487.0**	**52,763**	**6.56**	**3.73**
POLK STATION TOTAL	**952**	**137,373**	**20.7**	**79.9**	**93.1**	**10,151**	**-**	**-**	**-**	**1,394,488.7**	**4,445,853**	**3.24**	**-**
BAYSIDE ST 1	243	79,044	46.7	63.9	73.2	-		-	-	-	-	-	-
BAYSIDE CT1A	183	45,198	35.5	58.7	82.3	11,288	GAS	498,250	1,024,000	510,208.0	1,855,021	4.10	3.72
BAYSIDE CT1B	183	59,502	46.7	62.0	76.2	11,455	GAS	665,595	1,024,000	681,569.0	2,478,059	4.16	3.72
BAYSIDE CT1C	183	48,223	37.9	66.9	71.7	11,188	GAS	526,851	1,024,000	539,495.0	1,961,505	4.07	3.72
BAYSIDE UNIT 1 TOTAL	**792**	**231,967**	**42.1**	**61.5**	**65.9**	**7,463**	**GAS**	**1,690,696**	**1,024,000**	**1,731,272.0**	**6,294,585**	**2.71**	**3.72**
BAYSIDE ST 2	315	149,625	68.2	93.1	73.3	-		-	-	-	-	-	-
BAYSIDE CT2A	183	72,057	56.6	85.9	77.1	11,154	GAS	784,867	1,024,000	803,704.0	2,915,703	4.05	3.71
BAYSIDE CT2B	183	71,611	56.2	93.0	79.0	11,596	GAS	810,931	1,024,000	830,393.0	3,012,528	4.21	3.71
BAYSIDE CT2C	183	69,576	54.6	81.1	76.9	11,302	GAS	767,947	1,024,000	786,378.0	2,852,847	4.10	3.71
BAYSIDE CT2D	183	74,654	58.6	78.4	76.9	11,355	GAS	827,832	1,024,000	847,700.0	3,075,313	4.12	3.71
BAYSIDE UNIT 2 TOTAL	**1,047**	**437,523**	**60.0**	**84.6**	**64.5**	**7,470**	**GAS**	**3,191,577**	**1,024,000**	**3,268,175.0**	**11,856,391**	**2.71**	**3.71**
BAYSIDE UNIT 3 TOTAL	**61**	**708**	**1.7**	**100.0**	**85.2**	**11,621**	**GAS**	**8,035**	**1,024,000**	**8,228.0**	**29,858**	**4.22**	**3.72**
BAYSIDE UNIT 4 TOTAL	**61**	**1,711**	**4.0**	**100.0**	**98.8**	**10,865**	**GAS**	**18,154**	**1,024,000**	**18,590.0**	**67,548**	**3.95**	**3.72**
BAYSIDE UNIT 5 TOTAL	**61**	**234**	**0.6**	**100.0**	**76.7**	**12,876**	**GAS**	**2,942**	**1,024,000**	**3,013.0**	**10,936**	**4.67**	**3.72**
BAYSIDE UNIT 6 TOTAL	**61**	**63**	**0.1**	**100.0**	**65.2**	**14,270**	**GAS**	**878**	**1,024,000**	**899.0**	**3,269**	**5.19**	**3.72**
BAYSIDE STATION TOTAL	**2,083**	**672,206**	**46.4**	**77.6**	**65.1**	**7,483**	**GAS**	**4,912,282**	**1,024,000**	**5,030,177.0**	**18,262,587**	**2.72**	**3.72**
SYSTEM	**4,730**	**1,186,705**	**36.1**	**66.5**	**66.6**	**8,752**	**-**	**-**	**-**	**10,457,348.0**	**37,828,036**	**3.19**	**-**

Footnotes:

[1] As burned fuel cost system total includes ignition and excludes the Polk warm gas cleanup credit.

[2] Fuel burned (MM BTU) system total excludes ignition.

[3] Includes January adjustment of 3,070 tons consumed, $268,106 fuel expense, and 71,551.9 mmbtu's.

LEGEND:

B.B. = BIG BEND
CT = COMBUSTION TURBINE
NG = NATURAL GAS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: March 2016

SCHEDULE A4
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REVISED 5/20/16

(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**	**287**	**24.1**	**-**	**51.0**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
B.B.#1 NAT GAS CO-FIRE	142	65,089	61.7	91.8	67.1	-	NG CO-FIRE	696,649	1,023,000	712,672.0	2,236,081	3.44	3.21
B.B.#1 COAL	395	116,779	39.8	91.4	43.3	-	COAL	53,778	23,158,000	1,245,387.7	4,774,480	4.09	88.78
BIG BEND #1 TOTAL	**395**	**181,868**	**62.0**	**91.8**	**67.4**	**10,766**	**-**	**-**	**-**	**1,958,059.7**	**7,010,561**	**3.85**	**-**
B.B.#2 NAT GAS CO-FIRE	142	64,089	60.7	68.3	79.2	-	NG CO-FIRE	704,713	1,023,000	720,921.0	2,261,963	3.53	3.21
B.B.#2 COAL	395	80,419	27.4	66.0	35.7	-	COAL	37,890	23,158,000	877,466.8	3,363,923	4.18	88.78
BIG BEND #2 TOTAL	**395**	**144,508**	**49.2**	**68.3**	**64.2**	**11,061**	**-**	**-**	**-**	**1,598,387.8**	**5,625,886**	**3.89**	**-**
B.B.#3 NAT GAS CO-FIRE	142	100,847	95.6	53.5	107.6	-	NG CO-FIRE	1,036,869	1,023,000	1,060,718.0	3,328,111	3.30	3.21
B.B.#3 COAL	400	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
BIG BEND #3 TOTAL	**400**	**100,847**	**33.9**	**53.5**	**38.2**	**10,518**	**-**	**-**	**-**	**1,060,718.0**	**3,328,111**	**3.30**	**-**
B.B.#4 NAT GAS CO-FIRE	164	51,635	42.4	62.3	67.0	-	NG CO-FIRE	560,802	1,023,000	573,700.0	1,800,042	3.49	3.21
B.B.#4 COAL	442	51,050	15.5	62.4	24.6	-	COAL	24,284	22,770,000	552,938.0	2,155,965	4.22	88.78
BIG BEND #4 TOTAL	**442**	**102,685**	**31.3**	**62.3**	**49.5**	**10,972**	**-**	**-**	**-**	**1,126,638.0**	**3,956,007**	**3.85**	**-**
B.B. IGNITION	-	-	-	-	-	-	GAS	163,665	24,526,385	4,014,105.2	93,774	-	0.57
BIG BEND 1-4 COAL TOTAL	**1,632**	**248,248**	**20.5**	**55.0**	**25.7**	**10,779**	**COAL**	**115,952**	**23,076,742**	**2,675,792.5**	**10,294,368**	**4.15**	**88.78**
B.B. CT#4 (OIL)	61	0	0.0	67.6	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B. CT#4 (GAS)	61	845	1.9	67.6	76.5	11,950	GAS	9,871	1,023,000	10,097.9	31,684	3.75	3.21
BIG BEND CT #4 TOTAL	**61**	**845**	**1.9**	**67.6**	**76.5**	**11,950**	**-**	**-**	**-**	**10,097.9**	**31,684**	**3.75**	**-**
BIG BEND STATION TOTAL	**1,693**	**530,753**	**42.2**	**68.7**	**54.8**	**10,841**	**-**	**-**	**-**	**5,753,901.4**	**20,046,023**	**3.78**	**-**
POLK #1 GASIFIER	220	130,481	79.8	80.7	100.0	10,257	COAL	47,713	28,049,313	1,338,312.7	2,975,155	2.28	62.36
POLK #1 CT (GAS)	195	7,323	5.1	84.0	25.2	8,449	GAS	63,415	1,023,000	64,874.0	194,136	2.65	3.06
POLK #1 TOTAL	**220**	**137,804**	**84.3**	**84.0**	**100.3**	**10,161**	**-**	**-**	**-**	**1,403,186.7**	**3,169,291**	**2.30**	**-**
POLK #2 CT (GAS)	183	3,094	2.3	74.2	67.8	13,028	GAS	39,404	1,023,000	40,310.0	126,477	4.09	3.21
POLK #2 CT (OIL)	187	0	0.0	74.2	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**183**	**3,094**	**2.3**	**74.2**	**67.8**	**13,028**	**-**	**-**	**-**	**40,310.0**	**126,477**	**4.09**	**-**
POLK #3 CT (GAS)	183	12,264	9.0	100.0	14.9	10,588	GAS	126,937	1,023,000	129,857.0	407,440	3.32	3.21
POLK #3 CT (OIL)	187	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**183**	**12,264**	**9.0**	**100.0**	**14.9**	**10,588**	**-**	**-**	**-**	**129,857.0**	**407,440**	**3.32**	**-**
POLK #4 (GAS)	**183**	**2,273**	**1.7**	**99.0**	**61.0**	**14,219**	GAS	**31,592**	**1,023,000**	**32,319.0**	**101,404**	**4.46**	**3.21**
POLK #5 (GAS)	**183**	**1,158**	**0.9**	**5.1**	**56.5**	**13,675**	GAS	**15,480**	**1,023,000**	**15,836.0**	**49,687**	**4.29**	**3.21**
POLK STATION TOTAL	**952**	**156,593**	**22.1**	**72.9**	**68.0**	**10,336**	**-**	**-**	**-**	**1,621,508.7**	**3,854,299**	**2.46**	**-**
BAYSIDE ST 1	243	128,265	71.0	100.0	71.0	-		-	-	-	-	-	-
BAYSIDE CT1A	183	76,262	56.1	100.0	75.2	11,637	GAS	867,505	1,023,000	887,458.0	2,785,314	3.65	3.21
BAYSIDE CT1B	183	81,539	60.0	100.0	75.7	11,740	GAS	935,728	1,023,000	957,250.0	3,004,358	3.68	3.21
BAYSIDE CT1C	183	82,719	60.8	99.0	75.4	11,405	GAS	922,173	1,023,000	943,383.0	2,960,837	3.58	3.21
BAYSIDE UNIT 1 TOTAL	**792**	**368,785**	**62.7**	**99.7**	**62.7**	**7,560**	**GAS**	**2,725,406**	**1,023,000**	**2,788,091.0**	**8,750,509**	**2.37**	**3.21**
BAYSIDE ST 2	315	74,276	31.7	65.7	48.3	-		-	-	-	-	-	-
BAYSIDE CT2A	183	32,396	23.8	46.3	76.0	11,405	GAS	361,177	1,023,000	369,484.0	1,159,636	3.58	3.21
BAYSIDE CT2B	183	18,166	13.4	32.9	74.6	11,949	GAS	212,182	1,023,000	217,062.0	681,256	3.75	3.21
BAYSIDE CT2C	183	49,620	36.5	66.1	72.6	11,862	GAS	575,370	1,023,000	588,603.0	1,847,349	3.72	3.21
BAYSIDE CT2D	183	44,204	32.5	55.7	74.0	11,683	GAS	504,834	1,023,000	516,445.0	1,620,878	3.67	3.21
BAYSIDE UNIT 2 TOTAL	**1,047**	**218,662**	**28.1**	**49.8**	**42.8**	**7,736**	**GAS**	**1,653,563**	**1,023,000**	**1,691,594.0**	**5,309,119**	**2.43**	**3.21**
BAYSIDE UNIT 3 TOTAL	**61**	**1,032**	**2.3**	**80.8**	**79.2**	**12,013**	**GAS**	**12,118**	**1,023,000**	**12,397.0**	**38,908**	**3.77**	**3.21**
BAYSIDE UNIT 4 TOTAL	**61**	**2,757**	**6.1**	**84.1**	**90.8**	**11,284**	**GAS**	**30,410**	**1,023,000**	**31,109.0**	**97,637**	**3.54**	**3.21**
BAYSIDE UNIT 5 TOTAL	**61**	**1,363**	**3.0**	**62.2**	**81.8**	**11,396**	**GAS**	**15,184**	**1,023,000**	**15,533.0**	**48,751**	**3.58**	**3.21**
BAYSIDE UNIT 6 TOTAL	**61**	**453**	**1.0**	**87.8**	**76.6**	**12,196**	**GAS**	**5,401**	**1,023,000**	**5,525.0**	**17,340**	**3.83**	**3.21**
BAYSIDE STATION TOTAL	**2,083**	**593,052**	**38.3**	**72.2**	**53.6**	**7,662**	**GAS**	**4,442,082**	**1,023,000**	**4,544,249.0**	**14,262,264**	**2.40**	**3.21**
SYSTEM	**4,730**	**1,280,685**	**36.4**	**71.0**	**55.6**	**9,305**	**-**	**-**	**-**	**11,919,659.1**	**38,162,586**	**2.98**	**-**

Footnotes:

[1] As burned fuel cost system total includes ignition and excludes the Polk warm gas cleanup credit.

[2] Fuel burned (MM BTU) system total excludes ignition.

LEGEND:

B.B. = BIG BEND
CT = COMBUSTION TURBINE
NG = NATURAL GAS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: April 2016

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REVISED 6/20/16

(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**	**257**	**22.3**	**-**	**45.0**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
B.B.#1 NAT GAS CO-FIRE		181	53,468	41.0	61.7	66.3	-	NG CO-FIRE	573,090	1,022,000	585,698.0	1,872,764	3.50	3.27
B.B.#1 COAL		385	59,906	21.6	61.7	34.9	-	COAL	27,427	23,170,000	635,488.7	2,701,356	4.51	98.49
BIG BEND #1 TOTAL		**385**	**113,374**	**40.9**	**61.7**	**66.1**	**10,771**	**-**	**-**	**-**	**1,221,186.7**	**4,574,120**	**4.03**	**-**
B.B.#2 NAT GAS CO-FIRE		181	0	0.0	0.0	0.0	-	NG CO-FIRE	0	0	0.0	0	0.00	0.00
B.B.#2 COAL		385	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
BIG BEND #2 TOTAL		**385**	**0**	**0.0**	**0.0**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**0**	**0.00**	**-**
B.B.#3 NAT GAS CO-FIRE		181	93,144	71.5	59.3	76.2	-	NG CO-FIRE	964,388	1,022,000	985,606.0	3,151,465	3.38	3.27
B.B.#3 COAL		395	38,445	13.5	59.3	14.4	-	COAL	16,359	23,446,000	383,553.1	1,611,240	4.19	98.49
BIG BEND #3 TOTAL		**395**	**131,589**	**46.3**	**59.3**	**49.3**	**10,405**	**-**	**-**	**-**	**1,369,159.1**	**4,762,705**	**3.62**	**-**
B.B.#4 NAT GAS CO-FIRE		185	57,703	43.3	68.1	56.6	-	NG CO-FIRE	588,949	1,022,000	601,906.0	1,924,589	3.34	3.27
B.B.#4 COAL		437	91,462	29.1	67.9	38.0	-	COAL	40,427	23,118,000	934,595.8	3,981,760	4.35	98.49
BIG BEND #4 TOTAL		**437**	**149,165**	**47.4**	**68.1**	**61.9**	**10,301**	**-**	**-**	**-**	**1,536,501.8**	**5,906,349**	**3.96**	**-**
B.B. IGNITION		-	-	-	-	-	-	GAS	122,291	24,478,041	2,993,434.8	90,380	-	0.74
BIG BEND 1-4 COAL TOTAL		**1,602**	**189,813**	**16.5**	**48.0**	**27.9**	**10,292**	**COAL**	**84,213**	**23,198,652**	**1,953,637.6**	**8,294,356**	**4.37**	**98.49**
B.B. CT#4 (OIL)		0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B. CT#4 (GAS)		56	773	1.9	98.3	80.6	12,808	GAS	0	1,022,000	9,900.3	31,655	4.10	0.00
BIG BEND CT #4 TOTAL		**56**	**773**	**1.9**	**98.3**	**80.6**	**12,808**	**-**	**-**	**-**	**9,900.3**	**31,655**	**4.10**	**-**
BIG BEND STATION TOTAL		**1,658**	**394,901**	**33.1**	**49.7**	**58.1**	**10,475**	**-**	**-**	**-**	**4,136,747.9**	**15,365,209**	**3.89**	**-**
POLK #1 GASIFIER		220	106,727	67.4	67.4	99.9	9,743	COAL	38,077	27,307,599	1,039,797.2	2,162,068	2.03	56.78
POLK #1 CT (GAS)	[3]	195	11,352	8.1	75.2	31.3	8,106	GAS	87,111	1,022,000	89,024.0	294,246	2.59	3.38
POLK #1 TOTAL		**220**	**118,079**	**74.5**	**75.2**	**100.5**	**9,585**	**-**	**-**	**-**	**1,128,821.2**	**2,456,314**	**2.08**	**-**
POLK #2 CT (GAS)		151	889	0.8	5.3	58.8	15,487	GAS	13,472	1,022,000	13,768.0	44,023	4.95	3.27
POLK #2 CT (OIL)		159	19	0.0	5.3	21.7	15,796	LGT.OIL	52	5,772,544	300.6	6,639	34.94	127.67
POLK #2 TOTAL		**151**	**908**	**0.8**	**5.3**	**56.9**	**15,494**	**-**	**-**	**-**	**14,068.6**	**50,662**	**5.58**	**-**
POLK #3 CT (GAS)		151	6,002	5.5	79.5	76.5	11,994	GAS	70,440	1,022,000	71,990.0	230,187	3.84	3.27
POLK #3 CT (OIL)		159	0	0.0	79.5	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL		**151**	**6,002**	**5.5**	**79.5**	**76.5**	**11,994**	**-**	**-**	**-**	**71,990.0**	**230,187**	**3.84**	**-**
POLK #4 (GAS)		**151**	**9,445**	**8.7**	**99.7**	**77.7**	**12,057**	GAS	**111,425**	**1,022,000**	**113,876.0**	**364,117**	**3.86**	**3.27**
POLK #5 (GAS)		**151**	**6,576**	**6.0**	**99.8**	**85.1**	**11,001**	GAS	**70,785**	**1,022,000**	**72,342.0**	**231,313**	**3.52**	**3.27**
POLK STATION TOTAL		**824**	**141,010**	**23.8**	**72.2**	**96.0**	**9,957**	**-**	**-**	**-**	**1,401,097.8**	**3,332,593**	**2.36**	**-**
BAYSIDE ST 1		233	130,527	77.8	99.8	78.0	-		-	-	-	-	-	-
BAYSIDE CT1A		156	75,283	67.0	100.0	92.6	11,519	GAS	848,500	1,022,000	867,167.0	2,774,450	3.69	3.27
BAYSIDE CT1B		156	82,923	73.8	99.7	88.5	11,627	GAS	943,386	1,022,000	964,140.0	3,084,712	3.72	3.27
BAYSIDE CT1C		156	88,018	78.4	98.7	88.9	11,223	GAS	966,560	1,022,000	987,824.0	3,160,487	3.59	3.27
BAYSIDE UNIT 1 TOTAL		**701**	**376,751**	**74.6**	**99.3**	**74.8**	**7,483**	**GAS**	**2,758,446**	**1,022,000**	**2,819,131.0**	**9,019,649**	**2.39**	**3.27**
BAYSIDE ST 2		305	158,613	72.2	98.8	73.1	-		-	-	-	-	-	-
BAYSIDE CT2A		156	67,592	60.2	92.7	90.1	11,291	GAS	746,721	1,022,000	763,149.0	2,441,651	3.61	3.27
BAYSIDE CT2B		156	81,669	72.7	98.5	92.5	11,755	GAS	939,360	1,022,000	960,026.0	3,071,548	3.76	3.27
BAYSIDE CT2C		156	71,557	63.7	98.1	91.7	11,463	GAS	802,604	1,022,000	820,261.0	2,624,379	3.67	3.27
BAYSIDE CT2D		156	80,064	71.3	93.6	89.1	11,529	GAS	903,159	1,022,000	923,028.0	2,953,177	3.69	3.27
BAYSIDE UNIT 2 TOTAL		**929**	**459,495**	**68.7**	**94.5**	**69.5**	**7,544**	**GAS**	**3,391,844**	**1,022,000**	**3,466,464.0**	**11,090,755**	**2.41**	**3.27**
BAYSIDE UNIT 3 TOTAL		**56**	**1,294**	**3.2**	**87.5**	**78.2**	**11,971**	**GAS**	**15,157**	**1,022,000**	**15,490.0**	**49,559**	**3.83**	**3.27**
BAYSIDE UNIT 4 TOTAL		**56**	**2,769**	**6.9**	**97.6**	**93.3**	**11,436**	**GAS**	**30,983**	**1,022,000**	**31,665.0**	**101,310**	**3.66**	**3.27**
BAYSIDE UNIT 5 TOTAL		**56**	**227**	**0.6**	**98.3**	**82.2**	**13,273**	**GAS**	**2,948**	**1,022,000**	**3,013.0**	**9,640**	**4.25**	**3.27**
BAYSIDE UNIT 6 TOTAL		**56**	**782**	**1.9**	**98.3**	**93.0**	**11,520**	**GAS**	**8,815**	**1,022,000**	**9,009.0**	**28,824**	**3.69**	**3.27**
BAYSIDE STATION TOTAL		**1,854**	**841,318**	**63.0**	**96.4**	**71.9**	**7,541**	**GAS**	**6,208,193**	**1,022,000**	**6,344,772.0**	**20,299,737**	**2.41**	**3.27**
SYSTEM		**4,338**	**1,377,486**	**44.1**	**73.9**	**69.0**	**8,628**	**-**	**-**	**-**	**11,882,617.7**	**38,997,539**	**2.83**	**-**

Footnotes:

[1] As burned fuel cost system total includes ignition and excludes the Polk warm gas cleanup credit.

[2] Fuel burned (MM BTU) system total excludes ignition.

[3] Includes Polk 1 Natural Gas consumption adjustment of (2,932.55) MCF and (3,000.0) MM BTU for the month of March 2016.

LEGEND:

B.B. = BIG BEND
CT = COMBUSTION TURBINE
NG = NATURAL GAS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: May 2016

SCHEDULE A4
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(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**	**350**	**29.4**	**-**	**56.3**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
B.B.#1 NAT GAS CO-FIRE	181	278	0.2	68.4	4.7	-	NG CO-FIRE	2,989	1,020,000	3,049.0	11,871	4.27	3.97
B.B.#1 COAL	385	184,696	64.5	66.5	92.9	-	COAL	83,882	23,704,000	1,988,338.9	7,508,091	4.07	89.51
BIG BEND #1 TOTAL	**385**	**184,974**	**64.6**	**68.4**	**93.0**	**10,766**	**-**	**-**	**-**	**1,991,387.9**	**7,519,962**	**4.07**	**-**
B.B.#2 NAT GAS CO-FIRE	181	0	0.0	0.0	0.0	-	NG CO-FIRE	0	0	0.0	0	0.00	0.00
B.B.#2 COAL	385	0	0.0	0.0	0.0	-	COAL	0	0	0.0	0	0.00	0.00
BIG BEND #2 TOTAL	**385**	**0**	**0.0**	**0.0**	**0.0**	**0**	**-**	**-**	**-**	**0.0**	**0**	**0.00**	**-**
B.B.#3 NAT GAS CO-FIRE	181	294	0.2	74.2	4.9	-	NG CO-FIRE	3,087	1,020,000	3,149.0	12,260	4.17	3.97
B.B.#3 COAL	395	204,479	69.6	73.8	93.1	-	COAL	91,214	23,620,000	2,154,474.7	8,164,361	3.99	89.51
BIG BEND #3 TOTAL	**395**	**204,773**	**69.7**	**74.2**	**93.2**	**10,537**	**-**	**-**	**-**	**2,157,623.7**	**8,176,621**	**3.99**	**-**
B.B.#4 NAT GAS CO-FIRE	185	68	0.0	92.3	1.1	-	NG CO-FIRE	709	1,020,000	723.0	2,815	4.14	3.97
B.B.#4 COAL	437	255,804	78.7	82.3	84.6	-	COAL	113,295	23,630,000	2,677,160.9	10,140,783	3.96	89.51
BIG BEND #4 TOTAL	**437**	**255,872**	**78.7**	**92.3**	**84.7**	**10,466**	**-**	**-**	**-**	**2,677,883.9**	**10,143,598**	**3.96**	**-**
B.B. IGNITION	-	-	-	-	-	-	GAS	288,391	23,648,361	6,819,974.5	78,263	-	0.27
BIG BEND 1-4 COAL TOTAL	**1,602**	**644,979**	**54.1**	**56.6**	**89.5**	**10,574**	**COAL**	**288,391**	**23,648,361**	**6,819,974.5**	**25,813,235**	**4.00**	**89.51**
B.B. CT#4 (OIL)	56	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B. CT#4 (GAS)	56	2,096	5.0	100.0	93.7	11,323	GAS	23,268	1,020,000	23,733.8	92,404	4.41	3.97
BIG BEND CT #4 TOTAL	**56**	**2,096**	**5.0**	**99.8**	**93.7**	**11,323**	**-**	**-**	**-**	**23,733.8**	**92,404**	**4.41**	**-**
BIG BEND STATION TOTAL	**1,658**	**647,715**	**52.5**	**61.3**	**89.6**	**10,577**	**-**	**-**	**-**	**6,850,629.3**	**26,010,848**	**4.02**	**-**
POLK #1 GASIFIER [3]	220	(7,548)	0.0	0.0	0.0	0	COAL	0	0	0.0	57,201	(0.76)	0.00
POLK #1 CT (GAS)	195	10,431	7.2	10.2	70.7	9,024	GAS	92,288	1,020,000	94,134.0	366,493	3.51	3.97
POLK #1 TOTAL	**220**	**2,883**	**1.8**	**10.2**	**17.3**	**32,651**	**-**	**-**	**-**	**94,134.0**	**423,694**	**14.70**	**-**
POLK #2 CT (GAS)	151	17,773	15.8	87.5	81.0	11,505	GAS	200,476	1,020,000	204,486.0	796,127	4.48	3.97
POLK #2 CT (OIL)	159	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**151**	**17,773**	**15.8**	**100.0**	**81.0**	**11,505**	**-**	**-**	**-**	**204,486.0**	**796,127**	**4.48**	**-**
POLK #3 CT (GAS)	151	3,727	3.3	87.5	57.9	12,365	GAS	45,179	1,020,000	46,083.0	179,415	4.81	3.97
POLK #3 CT (OIL)	159	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**151**	**3,727**	**3.3**	**100.0**	**57.9**	**12,365**	**-**	**-**	**-**	**46,083.0**	**179,415**	**4.81**	**-**
POLK #4 (GAS)	**151**	**8,191**	**7.3**	**73.0**	**72.4**	**12,107**	GAS	**97,222**	**1,020,000**	**99,166.0**	**386,084**	**4.71**	**3.97**
POLK #5 (GAS)	**151**	**3,401**	**3.0**	**81.5**	**82.3**	**11,137**	GAS	**37,133**	**1,020,000**	**37,876.0**	**147,463**	**4.34**	**3.97**
POLK STATION TOTAL	**824**	**35,975**	**5.9**	**67.7**	**59.5**	**13,391**	**-**	**-**	**-**	**481,745.0**	**1,932,783**	**5.37**	**-**
BAYSIDE ST 1	233	115,538	66.6	100.0	66.6	-		-	-	-	-	-	-
BAYSIDE CT1A	156	64,889	55.9	95.6	85.7	11,327	GAS	720,580	1,020,000	734,991.0	2,862,511	4.41	3.97
BAYSIDE CT1B	156	76,309	65.7	100.0	87.8	11,434	GAS	855,377	1,020,000	872,485.0	3,397,993	4.45	3.97
BAYSIDE CT1C	156	75,662	65.2	99.4	85.9	11,082	GAS	822,042	1,020,000	838,483.0	3,265,570	4.32	3.97
BAYSIDE UNIT 1 TOTAL	**701**	**332,398**	**63.7**	**98.4**	**63.7**	**7,359**	**GAS**	**2,397,999**	**1,020,000**	**2,445,959.0**	**9,526,074**	**2.87**	**3.97**
BAYSIDE ST 2	305	145,381	64.1	100.0	64.1	-		-	-	-	-	-	-
BAYSIDE CT2A	156	73,153	63.0	96.1	85.9	11,145	GAS	799,309	1,020,000	815,295.0	3,175,262	4.34	3.97
BAYSIDE CT2B	156	67,132	57.8	100.0	86.7	11,491	GAS	756,308	1,020,000	771,434.0	3,004,440	4.48	3.97
BAYSIDE CT2C	156	62,164	53.6	99.9	87.3	11,301	GAS	688,757	1,020,000	702,532.0	2,736,093	4.40	3.97
BAYSIDE CT2D	156	72,636	62.6	100.0	86.5	11,332	GAS	807,006	1,020,000	823,146.0	3,205,838	4.41	3.97
BAYSIDE UNIT 2 TOTAL	**929**	**420,466**	**60.8**	**99.0**	**60.8**	**7,402**	**GAS**	**3,051,380**	**1,020,000**	**3,112,407.0**	**12,121,633**	**2.88**	**3.97**
BAYSIDE UNIT 3 TOTAL	**56**	**1,367**	**3.3**	**100.0**	**87.2**	**11,391**	**GAS**	**15,267**	**1,020,000**	**15,572.0**	**60,647**	**4.44**	**3.97**
BAYSIDE UNIT 4 TOTAL	**56**	**2,306**	**5.5**	**100.0**	**90.0**	**11,111**	**GAS**	**25,121**	**1,020,000**	**25,623.0**	**99,792**	**4.33**	**3.97**
BAYSIDE UNIT 5 TOTAL	**56**	**52**	**0.1**	**100.0**	**33.4**	**18,615**	**GAS**	**949**	**1,020,000**	**968.0**	**3,770**	**7.25**	**3.97**
BAYSIDE UNIT 6 TOTAL	**56**	**372**	**0.9**	**96.9**	**79.2**	**11,583**	**GAS**	**4,225**	**1,020,000**	**4,309.0**	**16,782**	**4.51**	**3.97**
BAYSIDE STATION TOTAL	**1,854**	**756,961**	**54.9**	**98.8**	**62.2**	**7,404**	**GAS**	**5,494,941**	**1,020,000**	**5,604,838.0**	**21,828,698**	**2.88**	**3.97**
B.B. IGNITION							**LGT.OIL**				**1,822,960**		
SYSTEM	**4,338**	**1,441,001**	**44.7**	**78.5**	**72.0**	**8,978**	**-**	**-**	**-**	**12,937,212.3**	**51,595,289**	**3.58**	**-**

Footnotes:
[1] As burned fuel cost system total includes ignition and excludes the Polk warm gas cleanup credit.
[2] Fuel burned (MM BTU) system total excludes ignition.
[3] Station Service

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE
NG = NATURAL GAS

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SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
MONTH OF: June 2016

SCHEDULE A4
PAGE 1 OF 1

(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**	**292**	**25.3**	**-**	**48.1**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
B.B.#1 NAT GAS CO-FIRE	181	5,635	4.3	88.4	35.8	-	NG CO-FIRE	60,102	1,018,000	61,184.0	226,337	4.02	3.77
B.B.#1 COAL	385	224,747	81.1	86.0	81.1	-	COAL	101,601	23,608,000	2,398,592.9	8,746,488	3.89	86.09
BIG BEND #1 TOTAL	**385**	**230,382**	**83.1**	**88.4**	**83.1**	**10,677**	**-**	**-**	**-**	**2,459,776.9**	**8,972,825**	**3.89**	**-**
B.B.#2 NAT GAS CO-FIRE	181	16,239	12.5	36.8	34.6	-	NG CO-FIRE	169,621	1,018,000	172,674.0	638,771	3.93	3.77
B.B.#2 COAL	385	67,162	24.2	35.4	49.4	-	COAL	29,495	23,710,000	699,326.5	2,539,125	3.78	86.09
BIG BEND #2 TOTAL	**385**	**83,401**	**30.1**	**36.8**	**61.3**	**10,456**	**-**	**-**	**-**	**872,000.5**	**3,177,896**	**3.81**	**-**
B.B.#3 NAT GAS CO-FIRE	181	589	0.5	52.7	3.8	-	NG CO-FIRE	6,340	1,018,000	6,454.0	23,875	4.05	3.77
B.B.#3 COAL	395	138,462	48.7	52.7	56.3	-	COAL	62,905	23,698,000	1,490,715.1	5,415,280	3.91	86.09
BIG BEND #3 TOTAL	**395**	**139,051**	**48.9**	**52.7**	**56.5**	**10,767**	**-**	**-**	**-**	**1,497,169.1**	**5,439,155**	**3.91**	**-**
B.B.#4 NAT GAS CO-FIRE	185	113	0.1	63.4	5.6	-	NG CO-FIRE	1,164	1,018,000	1,185.0	4,384	3.88	3.77
B.B.#4 COAL	437	184,415	58.6	63.4	70.3	-	COAL	80,539	23,716,000	1,910,051.1	6,933,331	3.76	86.09
BIG BEND #4 TOTAL	**437**	**184,528**	**58.6**	**63.4**	**70.3**	**10,357**	**-**	**-**	**-**	**1,911,236.1**	**6,937,715**	**3.76**	**-**
B.B. IGNITION	-	-	-	-	-	-	GAS	312,702	24,130,570	7,545,670.0	264,547	-	0.85
BIG BEND 1-4 COAL TOTAL	**1,602**	**614,786**	**53.3**	**59.5**	**66.7**	**10,571**	**COAL**	**274,540**	**23,671,263**	**6,498,685.6**	**23,634,224**	**3.84**	**86.09**
B.B. CT#4 (OIL)	56	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B. CT#4 (GAS)	56	2,657	6.6	100.0	90.2	11,624	GAS	30,339	1,018,000	30,885.6	114,256	4.30	3.77
BIG BEND CT #4 TOTAL	**56**	**2,657**	**6.6**	**100.0**	**90.2**	**11,624**	**-**	**-**	**-**	**30,885.6**	**114,256**	**4.30**	**-**
BIG BEND STATION TOTAL	**1,658**	**640,019**	**53.6**	**61.7**	**69.2**	**10,579**	**-**	**-**	**-**	**6,771,068.2**	**24,906,394**	**3.89**	**-**
POLK #1 GASIFIER	220	106,175	67.0	69.6	93.5	9,861	COAL	38,163	27,434,786	1,046,984.4	1,923,843	1.81	50.41
POLK #1 CT (GAS)	195	25,177	17.9	98.1	50.4	8,025	GAS	198,476	1,018,000	202,049.0	747,438	2.97	3.77
POLK #1 TOTAL	**220**	**131,352**	**82.9**	**98.1**	**90.9**	**9,509**	**-**	**-**	**-**	**1,249,033.4**	**2,671,281**	**2.03**	**-**
POLK #2 CT (GAS)	151	13,948	12.8	97.5	49.9	13,900	GAS	190,455	1,018,000	193,883.0	717,229	5.14	3.77
POLK #2 CT (OIL)	159	0	0.0	97.5	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**151**	**13,948**	**12.8**	**97.5**	**49.9**	**13,900**	**-**	**-**	**-**	**193,883.0**	**717,229**	**5.14**	**-**
POLK #3 CT (GAS)	151	14,467	13.3	79.1	56.4	12,828	GAS	182,311	1,018,000	185,593.0	686,562	4.75	3.77
POLK #3 CT (OIL)	159	0	0.0	79.1	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**151**	**14,467**	**13.3**	**79.1**	**56.4**	**12,828**	**-**	**-**	**-**	**185,593.0**	**686,562**	**4.75**	**-**
POLK #4 (GAS)	**151**	**14,209**	**13.1**	**96.2**	**44.0**	**14,557**	GAS	**203,181**	**1,018,000**	**206,838.0**	**765,153**	**5.38**	**3.77**
POLK #5 (GAS)	**151**	**11,118**	**10.2**	**96.2**	**39.6**	**14,211**	GAS	**155,203**	**1,018,000**	**157,997.0**	**584,476**	**5.26**	**3.77**
POLK STATION TOTAL	**824**	**185,094**	**31.2**	**93.8**	**71.6**	**10,769**	**-**	**-**	**-**	**1,993,344.4**	**5,424,701**	**2.93**	**-**
BAYSIDE ST 1	233	122,281	72.9	100.0	72.9	-		-	-	-	-	-	-
BAYSIDE CT1A	156	73,017	65.0	97.5	85.6	11,479	GAS	823,330	1,018,000	838,150.0	3,101,092	4.25	3.77
BAYSIDE CT1B	156	74,394	66.2	95.2	86.0	11,641	GAS	850,672	1,018,000	865,984.0	3,204,076	4.31	3.77
BAYSIDE CT1C	156	81,631	72.7	96.9	85.5	11,186	GAS	897,014	1,018,000	913,160.0	3,378,625	4.14	3.77
BAYSIDE UNIT 1 TOTAL	**701**	**351,323**	**69.6**	**96.6**	**69.6**	**7,450**	**GAS**	**2,571,016**	**1,018,000**	**2,617,294.0**	**9,683,793**	**2.76**	**3.77**
BAYSIDE ST 2	305	149,867	68.2	99.2	68.8	-		-	-	-	-	-	-
BAYSIDE CT2A	156	66,603	59.3	83.5	83.2	11,225	GAS	734,402	1,018,000	747,621.0	2,766,143	4.15	3.77
BAYSIDE CT2B	156	69,791	62.1	90.2	85.8	11,622	GAS	796,754	1,018,000	811,096.0	3,000,993	4.30	3.77
BAYSIDE CT2C	156	68,251	60.8	97.4	87.2	11,450	GAS	767,660	1,018,000	781,478.0	2,891,410	4.24	3.77
BAYSIDE CT2D	156	76,101	67.8	97.7	85.6	11,500	GAS	859,676	1,018,000	875,150.0	3,237,990	4.25	3.77
BAYSIDE UNIT 2 TOTAL	**929**	**430,613**	**64.4**	**91.4**	**64.9**	**7,467**	**GAS**	**3,158,492**	**1,018,000**	**3,215,345.0**	**11,896,536**	**2.76**	**3.77**
BAYSIDE UNIT 3 TOTAL	**56**	**2,174**	**5.4**	**100.0**	**93.2**	**11,222**	**GAS**	**23,965**	**1,018,000**	**24,396.0**	**90,263**	**4.15**	**3.77**
BAYSIDE UNIT 4 TOTAL	**56**	**3,233**	**8.0**	**100.0**	**89.7**	**11,170**	**GAS**	**35,475**	**1,018,000**	**36,114.0**	**133,619**	**4.13**	**3.77**
BAYSIDE UNIT 5 TOTAL	**56**	**280**	**0.7**	**100.0**	**82.0**	**12,896**	**GAS**	**3,547**	**1,018,000**	**3,611.0**	**13,360**	**4.77**	**3.77**
BAYSIDE UNIT 6 TOTAL	**56**	**917**	**2.3**	**97.9**	**79.6**	**11,646**	**GAS**	**10,490**	**1,018,000**	**10,679.0**	**39,512**	**4.31**	**3.77**
BAYSIDE STATION TOTAL	**1,854**	**788,540**	**59.1**	**94.3**	**67.1**	**7,492**	**GAS**	**5,802,985**	**1,018,000**	**5,907,439.0**	**21,857,083**	**2.77**	**3.77**
B.B. IGNITION							**LGT.OIL**				**(1,757)**		
SYSTEM	**4,338**	**1,613,945**	**51.7**	**81.7**	**68.4**	**9,091**	**-**	**-**	**-**	**14,671,851.6**	**52,186,421**	**3.23**	**-**

Footnotes:
[1] **As burned fuel cost system total includes ignition and excludes the Polk warm gas cleanup credit.**
[2] **Fuel burned (MM BTU) system total excludes ignition.**

LEGEND:
B.B. = BIG BEND
CT = COMBUSTION TURBINE
NG = NATURAL GAS

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SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2016

(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	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR [5]	0.0	0	0.0	-	0.0	-	SOLAR	-	-	-	-	-	-
3. TOTAL SOLAR [4]	**1.6**	**290**	**24.4**	**-**	**24.4**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
4. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
5. B.B.#1 COAL	-	185,610	-	-	-	10,568	COAL	82,590	23,750,333	1,961,540.0	6,715,894	3.62	81.32
6. TOTAL BIG BEND #1	**385**	**185,610**	**64.8**	**76.4**	**86.6**	**10,568**		**-**	**-**	**1,961,540.0**	**6,715,894**	**3.62**	**-**
7. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
8. B.B.#2 COAL	-	178,650	-	-	-	10,331	COAL	79,210	23,300,593	1,845,640.0	6,441,049	3.61	81.32
9. TOTAL BIG BEND #2	**385**	**178,650**	**62.4**	**85.0**	**84.7**	**10,331**		**-**	**-**	**1,845,640.0**	**6,441,049**	**3.61**	**-**
10. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
11. B.B.#3 COAL	-	195,660	-	-	-	10,409	COAL	88,550	22,999,322	2,036,590.0	7,200,539	3.68	81.32
12. TOTAL BIG BEND #3	**395**	**195,660**	**66.6**	**84.4**	**80.5**	**10,409**		**-**	**-**	**2,036,590.0**	**7,200,539**	**3.68**	**-**
13. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
14. B.B.#4 COAL	-	201,890	-	-	-	10,435	COAL	91,600	22,999,454	2,106,750.0	7,451,932	3.69	81.35
15. TOTAL BIG BEND #4	**437**	**201,890**	**62.1**	**81.6**	**81.3**	**10,435**		**-**	**-**	**2,106,750.0**	**7,451,932**	**3.69**	**-**
16. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	23,780	-	24,460.0	114,904	-	4.83
17. BIG BEND 1-4 COAL TOTAL	**1,602**	**761,810**	**63.9**	**81.8**	**83.1**	**10,436**	**COAL**	**341,950**	**23,250,534**	**7,950,520.0**	**27,809,414**	**3.65**	**81.33**
18. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
19. B.B.C.T.#4 GAS	56	2,280	5.5	-	92.5	11,921	GAS	26,450	1,027,599	27,180.0	127,806	5.61	4.83
20. B.B.C.T.#4 TOTAL	**56**	**2,280**	**5.5**	**98.2**	**92.5**	**11,921**	**-**	**-**	**-**	**27,180.0**	**127,806**	**5.61**	**-**
21. BIG BEND STATION TOTAL	**1,658**	**764,090**	**61.9**	**82.4**	**83.1**	**10,441**	**-**	**-**	**-**	**7,977,700.0**	**28,052,124**	**3.67**	**-**
22. POLK #1 GASIFIER	220	142,090	86.8	-	97.4	10,204	COAL	52,860	27,429,436	1,449,920.0	2,798,171	1.97	52.94
23. POLK #1 CT GAS	195	2,060	1.4	-	88.0	8,340	GAS	18,470	930,157	17,180.0	80,790	3.92	4.37
24. POLK #1 TOTAL	**220**	**144,150**	**88.1**	**82.5**	**97.3**	**10,178**	**-**	**-**	**-**	**1,467,100.0**	**2,878,961**	**2.00**	**-**
25. POLK #2 CT GAS	151	5,730	5.1	-	97.3	11,340	GAS	63,210	1,028,002	64,980.0	305,429	5.33	4.83
26. POLK #2 CC GAS-Testing [6]	-	85,200	-	-	-	6,788	GAS	562,630	1,027,994	578,380.0	2,718,610	3.19	4.83
27. POLK #2 CT OIL	159	110	0.1	-	17.3	10,727	LGT OIL	200	5,900,000	1,180.0	25,392	23.08	126.96
28. POLK #2 TOTAL	**151**	**91,040**	**81.0**	**21.1**	**89.5**	**7,080**	**-**	**-**	**-**	**644,540.0**	**3,049,431**	**3.35**	**-**
29. POLK #3 CT GAS	151	2,960	2.6	-	93.3	11,490	GAS	33,080	1,028,114	34,010.0	159,841	5.40	4.83
30. POLK #3 CT OIL	159	110	0.1	-	17.3	10,727	LGT OIL	200	5,900,000	1,180.0	25,391	23.08	126.96
31. POLK #3 TOTAL	**151**	**3,070**	**2.7**	**21.5**	**80.6**	**11,463**	**-**	**-**	**-**	**35,190.0**	**185,232**	**6.03**	**-**
32. POLK #4 CT GAS	**151**	**1,130**	**1.0**	**95.7**	**93.5**	**11,549**	**GAS**	**12,690**	**1,028,369**	**13,050.0**	**61,318**	**5.43**	**4.83**
33. POLK #5 CT GAS	**151**	**1,500**	**1.3**	**94.1**	**90.3**	**11,593**	**GAS**	**16,920**	**1,027,778**	**17,390.0**	**81,757**	**5.45**	**4.83**
34. POLK STATION TOTAL	**824**	**240,890**	**39.3**	**64.6**	**149.2**	**9,038**	**-**	**-**	**-**	**2,177,270.0**	**6,256,699**	**2.60**	**-**
35. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
36. BAYSIDE #1	701	342,500	65.7	91.6	66.9	7,419	GAS	2,471,880	1,027,999	2,541,090.0	11,944,043	3.49	4.83
37. BAYSIDE #2	929	363,230	52.6	93.2	54.2	7,613	GAS	2,690,000	1,028,000	2,765,320.0	12,997,991	3.58	4.83
38. BAYSIDE #3	56	330	0.8	98.6	84.2	12,515	GAS	4,020	1,027,363	4,130.0	19,425	5.89	4.83
39. BAYSIDE #4	56	140	0.3	98.6	83.3	13,000	GAS	1,780	1,022,472	1,820.0	8,601	6.14	4.83
40. BAYSIDE #5	56	900	2.2	98.6	89.3	12,067	GAS	10,570	1,027,436	10,860.0	51,074	5.67	4.83
41. BAYSIDE #6	56	460	1.1	98.6	91.3	12,022	GAS	5,380	1,027,881	5,530.0	25,996	5.65	4.83
42. BAYSIDE TOTAL	**1,854**	**707,560**	**51.3**	**93.2**	**59.7**	**7,531**	**GAS**	**5,183,630**	**1,027,996**	**5,328,750.0**	**25,047,130**	**3.54**	**4.83**
43. SYSTEM	**4,338**	**1,712,830**	**53.1**	**83.6**	**74.0**	**9,040**	**-**	**-**	**-**	**15,483,720.0**	**59,355,953**	**3.47**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition.
[2] Fuel burned (MM BTU) system total excludes ignition.
[3] City of Tampa on long term reserve standby.
[4] AC rating
[5] Commercial operation scheduled for November 2016
[6] Commercial operation scheduled for January 2017

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2016

(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	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR [5]	0.0	0	0.0	-	0.0	-	SOLAR	-	-	-	-	-	-
3. TOTAL SOLAR [4]	**1.6**	**290**	**24.4**	**-**	**24.4**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
4. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
5. B.B.#1 COAL	-	193,690	-	-	-	10,560	COAL	86,120	23,750,000	2,045,350.0	7,171,885	3.70	83.28
6. TOTAL BIG BEND #1	**385**	**193,690**	**67.6**	**76.4**	**87.0**	**10,560**		**-**	**-**	**2,045,350.0**	**7,171,885**	**3.70**	**-**
7. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
8. B.B.#2 COAL	-	179,040	-	-	-	10,294	COAL	79,100	23,299,368	1,842,980.0	6,587,271	3.68	83.28
9. TOTAL BIG BEND #2	**385**	**179,040**	**62.5**	**85.0**	**87.1**	**10,294**		**-**	**-**	**1,842,980.0**	**6,587,271**	**3.68**	**-**
10. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
11. B.B.#3 COAL	-	197,910	-	-	-	10,384	COAL	89,350	23,000,783	2,055,120.0	7,440,868	3.76	83.28
12. TOTAL BIG BEND #3	**395**	**197,910**	**67.3**	**84.4**	**82.4**	**10,384**		**-**	**-**	**2,055,120.0**	**7,440,868**	**3.76**	**-**
13. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
14. B.B.#4 COAL	-	185,630	-	-	-	10,418	COAL	84,080	23,000,714	1,933,900.0	7,005,885	3.77	83.32
15. TOTAL BIG BEND #4	**437**	**185,630**	**57.1**	**81.6**	**82.2**	**10,418**		**-**	**-**	**1,933,900.0**	**7,005,885**	**3.77**	**-**
16. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	14,600	-	15,020.0	56,937	-	3.90
17. BIG BEND 1-4 COAL TOTAL	**1,602**	**756,270**	**63.5**	**81.8**	**84.6**	**10,416**	**COAL**	**338,650**	**23,261,036**	**7,877,350.0**	**28,205,909**	**3.73**	**83.29**
18. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
19. B.B.C.T.#4 GAS	56	2,510	6.0	-	97.4	11,737	GAS	28,660	1,027,913	29,460.0	111,768	4.45	3.90
20. B.B.C.T.#4 TOTAL	**56**	**2,510**	**6.0**	**98.2**	**97.4**	**11,737**	**-**	**-**	**-**	**29,460.0**	**111,768**	**4.45**	**-**
21. BIG BEND STATION TOTAL	**1,658**	**758,780**	**61.5**	**82.4**	**84.6**	**10,420**	**-**	**-**	**-**	**7,906,810.0**	**28,374,614**	**3.74**	**-**
22. POLK #1 GASIFIER	220	142,090	86.8	-	97.4	10,204	COAL	52,860	27,429,436	1,449,920.0	2,874,961	2.02	54.39
23. POLK #1 CT GAS	195	6,150	4.2	-	95.6	8,324	GAS	51,550	993,016	51,190.0	194,210	3.16	3.77
24. POLK #1 TOTAL	**220**	**148,240**	**90.6**	**82.5**	**97.3**	**10,126**	**-**	**-**	**-**	**1,501,110.0**	**3,069,171**	**2.07**	**-**
25. POLK #2 CT GAS	151	2,050	1.8	-	97.0	11,361	GAS	22,660	1,027,802	23,290.0	88,369	4.31	3.90
26. POLK #2 CC GAS-Testing [6]	-	152,870	-	-	-	6,775	GAS	1,007,490	1,028,000	1,035,700.0	3,929,009	2.57	3.90
27. POLK #2 CT OIL	159	140	0.1	-	17.6	10,571	LGT OIL	260	5,692,308	1,480.0	32,835	23.45	126.29
28. POLK #2 TOTAL	**151**	**155,060**	**138.0**	**42.2**	**75.3**	**6,839**	**-**	**-**	**-**	**1,060,470.0**	**4,050,213**	**2.61**	**-**
29. POLK #3 CT GAS	151	3,820	3.4	-	97.3	11,317	GAS	42,050	1,028,062	43,230.0	163,987	4.29	3.90
30. POLK #3 CT OIL	159	140	0.1	-	17.6	10,571	LGT OIL	260	5,692,308	1,480.0	32,836	23.45	126.29
31. POLK #3 TOTAL	**151**	**3,960**	**3.5**	**95.3**	**83.9**	**11,290**	**-**	**-**	**-**	**44,710.0**	**196,823**	**4.97**	**-**
32. POLK #4 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
33. POLK #5 CT GAS	**151**	**910**	**0.8**	**42.5**	**100.4**	**11,209**	**GAS**	**9,920**	**1,028,226**	**10,200.0**	**38,686**	**4.25**	**3.90**
34. POLK STATION TOTAL	**824**	**308,170**	**50.3**	**55.0**	**191.6**	**8,490**	**-**	**-**	**-**	**2,616,490.0**	**7,354,893**	**2.39**	**-**
35. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
36. BAYSIDE #1	701	350,880	67.3	91.6	68.7	7,405	GAS	2,527,380	1,027,997	2,598,140.0	9,856,275	2.81	3.90
37. BAYSIDE #2	929	336,380	48.7	93.2	50.2	7,666	GAS	2,508,590	1,028,000	2,578,830.0	9,782,997	2.91	3.90
38. BAYSIDE #3	56	390	0.9	98.6	99.5	11,769	GAS	4,460	1,029,148	4,590.0	17,393	4.46	3.90
39. BAYSIDE #4	56	390	0.9	98.6	99.5	11,897	GAS	4,520	1,026,549	4,640.0	17,627	4.52	3.90
40. BAYSIDE #5	56	960	2.3	98.6	95.2	11,854	GAS	11,070	1,028,004	11,380.0	43,171	4.50	3.90
41. BAYSIDE #6	56	440	1.1	98.6	98.2	11,773	GAS	5,030	1,029,821	5,180.0	19,616	4.46	3.90
42. BAYSIDE TOTAL	**1,854**	**689,440**	**50.0**	**93.2**	**58.2**	**7,546**	**GAS**	**5,061,050**	**1,028,000**	**5,202,760.0**	**19,737,079**	**2.86**	**3.90**
43. SYSTEM	**4,338**	**1,756,680**	**54.4**	**81.8**	**74.6**	**8,952**	**-**	**-**	**-**	**15,726,060.0**	**55,466,586**	**3.16**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition.
[2] Fuel burned (MM BTU) system total excludes ignition.
[3] City of Tampa on long term reserve standby.
[4] AC rating
[5] Commercial operation scheduled for November 2016
[6] Commercial operation scheduled for January 2017

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2016

(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	1.6	260	22.6	-	22.6	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR [5]	0.0	0	0.0	-	0.0	-	SOLAR	-	-	-	-	-	-
3. TOTAL SOLAR [4]	**1.6**	**260**	**22.6**	**-**	**22.6**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
4. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
5. B.B.#1 COAL	-	175,760	-	-	-	10,527	COAL	77,910	23,748,941	1,850,280.0	6,396,582	3.64	82.10
6. TOTAL BIG BEND #1	**385**	**175,760**	**63.4**	**76.4**	**89.2**	**10,527**		**-**	**-**	**1,850,280.0**	**6,396,582**	**3.64**	**-**
7. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
8. B.B.#2 COAL	-	180,180	-	-	-	10,281	COAL	79,500	23,300,252	1,852,370.0	6,527,125	3.62	82.10
9. TOTAL BIG BEND #2	**385**	**180,180**	**65.0**	**85.0**	**88.5**	**10,281**		**-**	**-**	**1,852,370.0**	**6,527,125**	**3.62**	**-**
10. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
11. B.B.#3 COAL	-	45,600	-	-	-	10,528	COAL	20,870	23,003,833	480,090.0	1,713,474	3.76	82.10
12. TOTAL BIG BEND #3	**395**	**45,600**	**16.0**	**84.4**	**72.6**	**10,528**		**-**	**-**	**480,090.0**	**1,713,474**	**3.76**	**-**
13. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
14. B.B.#4 COAL	-	204,500	-	-	-	10,437	COAL	92,800	22,998,922	2,134,300.0	7,623,275	3.73	82.15
15. TOTAL BIG BEND #4	**437**	**204,500**	**65.0**	**81.6**	**81.1**	**10,437**		**-**	**-**	**2,134,300.0**	**7,623,275**	**3.73**	**-**
16. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	23,780	-	24,460.0	89,654	-	3.77
17. BIG BEND 1-4 COAL TOTAL	**1,602**	**606,040**	**52.5**	**81.8**	**84.7**	**10,423**	**COAL**	**271,080**	**23,303,232**	**6,317,040.0**	**22,260,456**	**3.67**	**82.12**
18. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
19. B.B.C.T.#4 GAS	56	1,120	2.8	-	95.2	12,054	GAS	13,140	1,027,397	13,500.0	49,540	4.42	3.77
20. B.B.C.T.#4 TOTAL	**56**	**1,120**	**2.8**	**98.2**	**95.2**	**12,054**	**-**	**-**	**-**	**13,500.0**	**49,540**	**4.42**	**-**
21. BIG BEND STATION TOTAL	**1,658**	**607,160**	**50.9**	**82.4**	**84.7**	**10,426**	**-**	**-**	**-**	**6,330,540.0**	**22,399,650**	**3.69**	**-**
22. POLK #1 GASIFIER	220	137,510	86.8	-	97.4	10,207	COAL	51,170	27,428,181	1,403,500.0	2,933,800	2.13	57.33
23. POLK #1 CT GAS	195	4,420	3.1	-	98.6	8,428	GAS	37,980	980,779	37,250.0	136,593	3.09	3.60
24. POLK #1 TOTAL	**220**	**141,930**	**89.6**	**82.5**	**97.4**	**10,151**	**-**	**-**	**-**	**1,440,750.0**	**3,070,393**	**2.16**	**-**
25. POLK #2 CT GAS	151	560	0.5	-	92.7	11,482	GAS	6,250	1,028,800	6,430.0	23,563	4.21	3.77
26. POLK #2 CC GAS-Testing [6]	-	205,810	-	-	-	6,783	GAS	1,358,090	1,027,995	1,396,110.0	5,120,214	2.49	3.77
27. POLK #2 CT OIL	159	110	0.1	-	17.3	11,091	LGT OIL	210	5,809,524	1,220.0	26,410	24.01	125.76
28. POLK #2 TOTAL	**151**	**206,480**	**189.9**	**0.0**	**54.0**	**6,799**	**-**	**-**	**-**	**1,403,760.0**	**5,170,187**	**2.50**	**-**
29. POLK #3 CT GAS	151	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
30. POLK #3 CT OIL	159	110	0.1	-	17.3	11,091	LGT OIL	210	5,809,524	1,220.0	26,410	24.01	125.76
31. POLK #3 TOTAL	**151**	**110**	**0.1**	**95.3**	**17.3**	**11,091**	**-**	**-**	**-**	**1,220.0**	**26,410**	**24.01**	**-**
32. POLK #4 CT GAS	**151**	**1,080**	**1.0**	**95.7**	**89.4**	**11,648**	**GAS**	**12,240**	**1,027,778**	**12,580.0**	**46,147**	**4.27**	**3.77**
33. POLK #5 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
34. POLK STATION TOTAL	**824**	**349,600**	**58.9**	**57.0**	**234.9**	**8,176**	**-**	**-**	**-**	**2,858,310.0**	**8,313,137**	**2.38**	**-**
35. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
36. BAYSIDE #1	701	333,780	66.1	91.6	72.6	7,374	GAS	2,394,230	1,027,996	2,461,260.0	9,026,625	2.70	3.77
37. BAYSIDE #2	929	341,650	51.1	93.2	52.6	7,627	GAS	2,534,850	1,027,998	2,605,820.0	9,556,785	2.80	3.77
38. BAYSIDE #3	56	150	0.4	98.6	89.3	12,467	GAS	1,820	1,027,473	1,870.0	6,862	4.57	3.77
39. BAYSIDE #4	56	50	0.1	98.6	89.3	13,000	GAS	640	1,015,625	650.0	2,413	4.83	3.77
40. BAYSIDE #5	56	470	1.2	98.6	93.3	12,149	GAS	5,560	1,026,978	5,710.0	20,962	4.46	3.77
41. BAYSIDE #6	56	260	0.6	98.6	92.9	12,038	GAS	3,040	1,029,605	3,130.0	11,461	4.41	3.77
42. BAYSIDE TOTAL	**1,854**	**676,360**	**50.7**	**93.2**	**60.9**	**7,508**	**GAS**	**4,940,140**	**1,027,995**	**5,078,440.0**	**18,625,108**	**2.75**	**3.77**
43. SYSTEM	**4,338**	**1,633,380**	**52.3**	**82.2**	**78.3**	**8,735**	**-**	**-**	**-**	**14,267,290.0**	**49,337,895**	**3.02**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition.
[2] Fuel burned (MM BTU) system total excludes ignition.
[3] City of Tampa on long term reserve standby.
[4] AC rating
[5] Commercial operation scheduled for November 2016
[6] Commercial operation scheduled for January 2017

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2016

(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	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR [5]	0.0	0	0.0	-	0.0	-	SOLAR	-	-	-	-	-	-
3. TOTAL SOLAR [4]	**1.6**	**290**	**24.4**	**-**	**24.4**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
4. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
5. B.B.#1 COAL	-	145,490	-	-	-	10,513	COAL	64,400	23,750,000	1,529,500.0	5,171,052	3.55	80.30
6. TOTAL BIG BEND #1	**385**	**145,490**	**50.8**	**76.4**	**90.6**	**10,513**		**-**	**-**	**1,529,500.0**	**5,171,052**	**3.55**	**-**
7. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
8. B.B.#2 COAL	-	14,720	-	-	-	10,339	COAL	6,530	23,306,279	152,190.0	524,332	3.56	80.30
9. TOTAL BIG BEND #2	**385**	**14,720**	**5.1**	**85.0**	**86.9**	**10,339**		**-**	**-**	**152,190.0**	**524,332**	**3.56**	**-**
10. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
11. B.B.#3 COAL	-	158,900	-	-	-	10,343	COAL	71,460	22,998,880	1,643,500.0	5,737,938	3.61	80.30
12. TOTAL BIG BEND #3	**395**	**158,900**	**54.1**	**57.2**	**85.6**	**10,343**		**-**	**-**	**1,643,500.0**	**5,737,938**	**3.61**	**-**
13. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
14. B.B.#4 COAL	-	214,550	-	-	-	10,413	COAL	97,130	23,000,515	2,234,040.0	7,802,316	3.64	80.33
15. TOTAL BIG BEND #4	**437**	**214,550**	**66.0**	**73.7**	**82.4**	**10,413**		**-**	**-**	**2,234,040.0**	**7,802,316**	**3.64**	**-**
16. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	16,690	-	17,160.0	72,435	-	4.34
17. BIG BEND 1-4 COAL TOTAL	**1,602**	**533,660**	**44.8**	**73.0**	**85.6**	**10,417**	**COAL**	**239,520**	**23,209,878**	**5,559,230.0**	**19,235,638**	**3.60**	**80.31**
18. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
19. B.B.C.T.#4 GAS	56	390	0.9	-	99.5	11,846	GAS	4,500	1,026,667	4,620.0	19,530	5.01	4.34
20. B.B.C.T.#4 TOTAL	**56**	**390**	**0.9**	**98.2**	**99.5**	**11,846**	**-**	**-**	**-**	**4,620.0**	**19,530**	**5.01**	**-**
21. BIG BEND STATION TOTAL	**1,658**	**534,050**	**43.3**	**73.8**	**85.6**	**10,418**	**-**	**-**	**-**	**5,563,850.0**	**19,327,603**	**3.62**	**-**
22. POLK #1 GASIFIER	220	142,090	86.8	-	97.4	10,204	COAL	52,860	27,429,436	1,449,920.0	3,020,419	2.13	57.14
23. POLK #1 CT GAS	195	1,100	0.8	-	94.0	8,482	GAS	10,830	861,496	9,330.0	39,407	3.58	3.64
24. POLK #1 TOTAL	**220**	**143,190**	**87.5**	**82.5**	**97.4**	**10,191**	**-**	**-**	**-**	**1,459,250.0**	**3,059,826**	**2.14**	**-**
25. POLK #2 CT GAS	151	600	0.5	-	99.3	11,383	GAS	6,650	1,027,068	6,830.0	28,861	4.81	4.34
26. POLK #2 CC GAS-Testing [6]	-	97,650	-	-	-	6,807	GAS	646,570	1,027,994	664,670.0	2,806,118	2.87	4.34
27. POLK #2 CT OIL	159	110	0.1	-	17.3	10,727	LGT OIL	200	5,900,000	1,180.0	25,054	22.78	125.27
28. POLK #2 TOTAL	**151**	**98,360**	**87.6**	**0.0**	**57.3**	**6,839**	**-**	**-**	**-**	**672,680.0**	**2,860,033**	**2.91**	**-**
29. POLK #3 CT GAS	151	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
30. POLK #3 CT OIL	159	110	0.1	-	17.3	10,727	LGT OIL	200	5,900,000	1,180.0	25,055	22.78	125.28
31. POLK #3 TOTAL	**151**	**110**	**0.1**	**95.3**	**17.3**	**10,727**	**-**	**-**	**-**	**1,180.0**	**25,055**	**22.78**	**-**
32. POLK #4 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
33. POLK #5 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
34. POLK STATION TOTAL	**824**	**241,660**	**39.4**	**39.5**	**162.3**	**8,827**	**-**	**-**	**-**	**2,133,110.0**	**5,944,914**	**2.46**	**-**
35. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
36. BAYSIDE #1	701	382,330	73.3	91.6	75.9	7,354	GAS	2,734,980	1,028,000	2,811,560.0	11,869,830	3.10	4.34
37. BAYSIDE #2	929	382,780	55.4	93.2	57.1	7,567	GAS	2,817,740	1,027,998	2,896,630.0	12,229,008	3.19	4.34
38. BAYSIDE #3	56	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
39. BAYSIDE #4	56	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
40. BAYSIDE #5	56	150	0.4	98.6	89.3	12,733	GAS	1,870	1,021,390	1,910.0	8,116	5.41	4.34
41. BAYSIDE #6	56	50	0.1	98.6	89.3	12,000	GAS	590	1,016,949	600.0	2,561	5.12	4.34
42. BAYSIDE TOTAL	**1,854**	**765,310**	**55.5**	**87.3**	**65.1**	**7,462**	**GAS**	**5,555,180**	**1,027,995**	**5,710,700.0**	**24,109,515**	**3.15**	**4.34**
43. SYSTEM	**4,338**	**1,541,310**	**47.8**	**73.0**	**74.8**	**8,699**	**-**	**-**	**-**	**13,407,660.0**	**49,382,032**	**3.20**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition.
[2] Fuel burned (MM BTU) system total excludes ignition.
[3] City of Tampa on long term reserve standby.
[4] AC rating
[5] Commercial operation scheduled for November 2016
[6] Commercial operation scheduled for January 2017

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2016

(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	1.6	270	23.4	-	23.4	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	170	15.7	-	15.7	-	SOLAR	-	-	-	-	-	-
3. TOTAL SOLAR [4]	**3.1**	**440**	**19.7**	**-**	**19.7**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
4. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
5. B.B.#1 COAL	-	56,880	-	-	-	10,601	COAL	25,390	23,748,720	602,980.0	1,912,332	3.36	75.32
6. TOTAL BIG BEND #1	**385**	**56,880**	**20.5**	**76.4**	**86.9**	**10,601**		**-**	**-**	**602,980.0**	**1,912,332**	**3.36**	**-**
7. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
8. B.B.#2 COAL	-	73,120	-	-	-	10,365	COAL	32,530	23,298,186	757,890.0	2,450,099	3.35	75.32
9. TOTAL BIG BEND #2	**385**	**73,120**	**26.4**	**85.0**	**83.3**	**10,365**		**-**	**-**	**757,890.0**	**2,450,099**	**3.35**	**-**
10. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
11. B.B.#3 COAL	-	191,210	-	-	-	10,390	COAL	86,380	22,999,305	1,986,680.0	6,505,988	3.40	75.32
12. TOTAL BIG BEND #3	**395**	**191,210**	**67.2**	**84.4**	**81.9**	**10,390**		**-**	**-**	**1,986,680.0**	**6,505,988**	**3.40**	**-**
13. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
14. B.B.#4 COAL	-	189,400	-	-	-	10,357	COAL	85,280	23,001,290	1,961,550.0	6,432,969	3.40	75.43
15. TOTAL BIG BEND #4	**437**	**189,400**	**60.2**	**62.5**	**90.1**	**10,357**		**-**	**-**	**1,961,550.0**	**6,432,969**	**3.40**	**-**
16. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	25,880	-	26,600.0	84,904	-	3.28
17. BIG BEND 1-4 COAL TOTAL	**1,602**	**510,610**	**44.3**	**76.6**	**85.5**	**10,398**	**COAL**	**229,580**	**23,125,272**	**5,309,100.0**	**17,301,388**	**3.39**	**75.36**
18. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
19. B.B.C.T.#4 GAS	56	560	1.4	-	90.9	11,911	GAS	6,490	1,027,735	6,670.0	21,291	3.80	3.28
20. B.B.C.T.#4 TOTAL	**56**	**560**	**1.4**	**98.2**	**90.9**	**11,911**	**-**	**-**	**-**	**6,670.0**	**21,291**	**3.80**	**-**
21. BIG BEND STATION TOTAL	**1,658**	**511,170**	**42.8**	**77.4**	**85.6**	**10,399**	**-**	**-**	**-**	**5,315,770.0**	**17,407,583**	**3.41**	**-**
22. POLK #1 GASIFIER	220	105,430	66.6	-	97.4	10,243	COAL	39,230	27,526,638	1,079,870.0	2,290,993	2.17	58.40
23. POLK #1 CT GAS	195	5,040	3.6	-	95.7	8,337	GAS	46,130	910,904	42,020.0	134,113	2.66	2.91
24. POLK #1 TOTAL	**220**	**110,470**	**69.7**	**68.7**	**97.3**	**10,156**	**-**	**-**	**-**	**1,121,890.0**	**2,425,106**	**2.20**	**-**
25. POLK #2 CT GAS	151	0	0.0	-	0.0	0	GAS	0	0	0.0	1	0.00	0.00
26. POLK #2 CC GAS-Testing [5]	-	237,720	-	-	-	6,747	GAS	1,560,250	1,028,002	1,603,940.0	5,118,628	2.15	3.28
27. POLK #2 CT OIL	159	140	0.1	-	17.6	10,857	LGT OIL	260	5,846,154	1,520.0	32,424	23.16	124.71
28. POLK #2 TOTAL	**151**	**237,860**	**218.8**	**81.0**	**17.6**	**6,750**	**-**	**-**	**-**	**1,605,460.0**	**5,151,053**	**2.17**	**-**
29. POLK #3 CT GAS	151	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
30. POLK #3 CT OIL	159	110	0.1	-	17.3	11,091	LGT OIL	210	5,809,524	1,220.0	26,189	23.81	124.71
31. POLK #3 TOTAL	**151**	**110**	**0.1**	**12.7**	**17.3**	**11,091**	**-**	**-**	**-**	**1,220.0**	**26,189**	**23.81**	**-**
32. POLK #4 CT GAS	**151**	**600**	**0.6**	**60.6**	**99.3**	**11,383**	**GAS**	**6,650**	**1,027,068**	**6,830.0**	**21,816**	**3.64**	**3.28**
33. POLK #5 CT GAS	**151**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
34. POLK STATION TOTAL	**824**	**349,040**	**58.8**	**46.6**	**302.1**	**7,837**	**-**	**-**	**-**	**2,735,400.0**	**7,624,164**	**2.18**	**-**
35. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
36. BAYSIDE #1	701	164,650	32.6	61.0	60.4	7,475	GAS	1,197,180	1,027,999	1,230,700.0	3,927,524	2.39	3.28
37. BAYSIDE #2	929	232,630	34.8	79.2	35.8	7,960	GAS	1,801,280	1,028,002	1,851,720.0	5,909,362	2.54	3.28
38. BAYSIDE #3	56	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
39. BAYSIDE #4	56	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
40. BAYSIDE #5	56	180	0.4	98.6	80.4	12,944	GAS	2,270	1,026,432	2,330.0	7,447	4.14	3.28
41. BAYSIDE #6	56	50	0.1	98.6	89.3	11,200	GAS	540	1,037,037	560.0	1,772	3.54	3.28
42. BAYSIDE TOTAL	**1,854**	**397,510**	**29.8**	**68.7**	**43.1**	**7,762**	**GAS**	**3,001,270**	**1,028,001**	**3,085,310.0**	**9,846,105**	**2.48**	**3.28**
43. SYSTEM	**4,339**	**1,258,160**	**40.3**	**67.8**	**72.1**	**8,851**	**-**	**-**	**-**	**11,136,480.0**	**34,877,852**	**2.77**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition.
[2] Fuel burned (MM BTU) system total excludes ignition.
[3] City of Tampa on long term reserve standby.
[4] AC rating
[5] Commercial operation scheduled for January 2017

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2016

(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	1.6	260	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	150	13.4	-	13.4	-	SOLAR	-	-	-	-	-	-
3. TOTAL SOLAR [4]	**3.1**	**410**	**17.8**	**-**	**17.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
4. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
5. B.B.#1 COAL	-	158,580	-	-	-	10,536	COAL	70,350	23,749,112	1,670,750.0	5,669,520	3.58	80.59
6. TOTAL BIG BEND #1	**395**	**158,580**	**54.0**	**51.7**	**81.9**	**10,536**		**-**	**-**	**1,670,750.0**	**5,669,520**	**3.58**	**-**
7. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
8. B.B.#2 COAL	-	179,860	-	-	-	10,315	COAL	79,630	23,299,008	1,855,300.0	6,417,398	3.57	80.59
9. TOTAL BIG BEND #2	**395**	**179,860**	**61.2**	**57.6**	**83.2**	**10,315**		**-**	**-**	**1,855,300.0**	**6,417,398**	**3.57**	**-**
10. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
11. B.B.#3 COAL	-	190,830	-	-	-	10,410	COAL	86,370	23,000,232	1,986,530.0	6,960,575	3.65	80.59
12. TOTAL BIG BEND #3	**400**	**190,830**	**64.1**	**84.4**	**76.7**	**10,410**		**-**	**-**	**1,986,530.0**	**6,960,575**	**3.65**	**-**
13. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
14. B.B.#4 COAL	-	22,020	-	-	-	10,539	COAL	10,090	23,000,000	232,070.0	816,612	3.71	80.93
15. TOTAL BIG BEND #4	**442**	**22,020**	**6.7**	**81.6**	**75.5**	**10,539**		**-**	**-**	**232,070.0**	**816,612**	**3.71**	**-**
16. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	18,770	-	19,310.0	64,261	-	3.42
17. BIG BEND 1-4 COAL TOTAL	**1,632**	**551,290**	**45.4**	**69.2**	**80.2**	**10,420**	**COAL**	**246,440**	**23,310,542**	**5,744,650.0**	**19,864,105**	**3.60**	**80.60**
18. B.B.C.T.#4 OIL	61	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
19. B.B.C.T.#4 GAS	61	2,250	5.0	-	75.3	12,378	GAS	27,080	1,028,434	27,850.0	92,710	4.12	3.42
20. B.B.C.T.#4 TOTAL	**61**	**2,250**	**5.0**	**98.2**	**75.3**	**12,378**	**-**	**-**	**-**	**27,850.0**	**92,710**	**4.12**	**-**
21. BIG BEND STATION TOTAL	**1,693**	**553,540**	**43.9**	**70.3**	**80.2**	**10,428**	**-**	**-**	**-**	**5,772,500.0**	**20,021,076**	**3.62**	**-**
22. POLK #1 GASIFIER	220	141,870	86.7	-	97.3	10,222	COAL	52,810	27,459,951	1,450,160.0	3,109,117	2.19	58.87
23. POLK #1 CT GAS	195	2,670	1.8	-	85.6	8,247	GAS	24,930	883,273	22,020.0	73,367	2.75	2.94
24. POLK #1 TOTAL	**220**	**144,540**	**88.3**	**82.5**	**97.0**	**10,185**	**-**	**-**	**-**	**1,472,180.0**	**3,182,484**	**2.20**	**-**
25. POLK #2 CT GAS	183	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
26. POLK #2 CC GAS-Testing [5]	-	272,770	-	-	-	6,767	GAS	1,795,610	1,028,002	1,845,890.0	6,147,413	2.25	3.42
27. POLK #2 CT OIL	187	110	0.1	-	14.7	10,364	LGT OIL	200	5,700,000	1,140.0	24,837	22.58	124.19
28. POLK #2 TOTAL	**183**	**272,880**	**200.4**	**72.4**	**14.7**	**6,769**	**-**	**-**	**-**	**1,847,030.0**	**6,172,250**	**2.26**	**-**
29. POLK #3 CT GAS	183	0	0.0	-	0.0	0	GAS	0	0	0.0	0	0.00	0.00
30. POLK #3 CT OIL	187	130	0.1	-	13.9	11,077	LGT OIL	250	5,760,000	1,440.0	31,045	23.88	124.18
31. POLK #3 TOTAL	**183**	**130**	**0.1**	**61.5**	**13.9**	**11,077**	**-**	**-**	**-**	**1,440.0**	**31,045**	**23.88**	**-**
32. POLK #4 CT GAS	**183**	**3,680**	**2.7**	**95.7**	**83.8**	**11,313**	**GAS**	**40,500**	**1,027,901**	**41,630.0**	**138,655**	**3.77**	**3.42**
33. POLK #5 CT GAS	**183**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
34. POLK STATION TOTAL	**952**	**421,230**	**59.5**	**63.2**	**271.7**	**7,982**	**-**	**-**	**-**	**3,362,280.0**	**9,524,434**	**2.26**	**-**
35. CITY OF TAMPA GAS [3]	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
36. BAYSIDE #1	792	314,100	53.3	91.6	54.7	7,365	GAS	2,250,420	1,027,999	2,313,430.0	7,704,492	2.45	3.42
37. BAYSIDE #2	1,047	132,950	17.1	75.2	24.8	8,167	GAS	1,056,280	1,027,985	1,085,840.0	3,616,258	2.72	3.42
38. BAYSIDE #3	61	580	1.3	98.6	95.1	11,810	GAS	6,660	1,028,529	6,850.0	22,801	3.93	3.42
39. BAYSIDE #4	61	470	1.0	98.6	96.3	11,915	GAS	5,450	1,027,523	5,600.0	18,659	3.97	3.42
40. BAYSIDE #5	61	1,590	3.5	98.6	84.1	12,082	GAS	18,690	1,027,822	19,210.0	63,987	4.02	3.42
41. BAYSIDE #6	61	1,150	2.5	98.6	89.8	11,991	GAS	13,410	1,028,337	13,790.0	45,910	3.99	3.42
42. BAYSIDE TOTAL	**2,083**	**450,840**	**29.1**	**84.2**	**40.4**	**7,641**	**GAS**	**3,350,910**	**1,027,995**	**3,444,720.0**	**11,472,107**	**2.54**	**3.42**
43. SYSTEM	**4,731**	**1,426,020**	**40.5**	**74.9**	**68.1**	**8,821**	**-**	**-**	**-**	**12,579,500.0**	**41,017,617**	**2.88**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE

[1] As burned fuel cost system total includes ignition.
[2] Fuel burned (MM BTU) system total excludes ignition.
[3] City of Tampa on long term reserve standby.
[4] AC rating
[5] Commercial operation scheduled for January 2017

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ACTUAL FOR THE PERIOD: JANUARY 2016 THROUGH JUNE 2016

SCHEDULE E5

	ACTUAL					
	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
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	-25,672	0
16. UNIT COST ($/BBL)	0.00	0.00	0.00	0.00	56.98	0.00
17. AMOUNT ($)	0	0	0	0	-1,462,845	-1,757
18. BURNED:						
19. UNITS (BBL)	65	415	0	52	0	0
20. UNIT COST ($/BBL)	127.62	127.43	0.00	127.67	0.00	0.00
21. AMOUNT ($)	8,295	52,885	0	6,639	1,822,960	-1,757
22. ENDING INVENTORY:						
23. UNITS (BBL)	72,029	71,335	71,000	70,569	44,488	44,488
24. UNIT COST ($/BBL)	127.78	127.78	127.78	127.78	127.48	127.48
25. AMOUNT ($)	9,203,985	9,115,198	9,072,297	9,017,047	5,671,463	5,671,463
26. DAYS SUPPLY: NORMAL	4,171	4,517	4,917	5,527	3,894	4,389
27. DAYS SUPPLY: EMERGENCY	10	10	10	10	6	6
COAL						
28. PURCHASES:						
29. UNITS (TONS)	303,664	112,618	249,385	140,628	238,574	171,505
30. UNIT COST ($/TON)	77.33	81.00	76.06	76.65	72.16	82.58
31. AMOUNT ($)	23,483,660	9,122,104	18,968,358	10,779,062	17,215,446	14,162,917
32. BURNED:						
33. UNITS (TONS)	237,150	157,333	163,665	122,290	288,391	312,703
34. UNIT COST ($/TON)	74.36	87.21	81.65	84.42	89.75	82.58
35. AMOUNT ($)	17,634,085	13,721,127	13,363,297	10,323,782	25,882,809	25,822,614
36. ENDING INVENTORY:						
37. UNITS (TONS)	579,096	534,381	620,101	638,439	588,622	447,424
38. UNIT COST ($/TON)	77.35	79.85	80.49	81.05	75.93	74.57
39. AMOUNT ($)	44,794,062	42,668,639	49,913,276	51,745,485	44,695,175	33,362,242
40. DAYS SUPPLY:	54	67	87	84	65	42
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	6,729,128	6,654,087	7,742,291	8,763,433	6,062,885	6,995,505
43. UNIT COST ($/MCF)	3.82	3.69	3.21	3.27	3.96	3.81
44. AMOUNT ($)	25,725,325	24,521,737	24,865,431	28,659,860	24,033,004	26,685,250
45. BURNED:						
46. UNITS (MCF)	6,971,622	6,475,412	7,727,814	8,687,853	5,997,292	7,000,177
47. UNIT COST ($/MCF)	3.75	3.70	3.21	3.27	3.97	3.77
48. AMOUNT ($)	26,171,136	23,962,511	24,799,289	28,444,096	23,823,630	26,365,564
49. ENDING INVENTORY:						
50. UNITS (MCF)	676,046	854,721	869,198	944,778	1,010,371	1,005,699
51. UNIT COST ($/MCF)	2.53	2.44	2.37	2.30	2.25	2.29
52. AMOUNT ($)	1,712,009	2,082,005	2,057,879	2,176,912	2,275,747	2,304,588
53. DAYS SUPPLY:	3	4	4	5	5	5
NUCLEAR						
54. BURNED:						
55. UNITS (MMBTU)	0	0	0	0	0	0
56. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT ($)	0	0	0	0	0	0
OTHER						
58. PURCHASES:						
59. UNITS (MMBTU)	0	0	0	0	0	0
60. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT ($)	0	0	0	0	0	0
62. BURNED:						
63. UNITS (MMBTU)	0	0	0	0	0	0
64. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT ($)	0	0	0	0	0	0
66. ENDING INVENTORY:						
67. UNITS (MMBTU)	0	0	0	0	0	0
68. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT ($)	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-IGNITION, OTHER USAGE, AND ANALYSIS (2) COAL-IGNITION, ADDITIVES, ANALYSIS, AND INVENTORY ADJUSTMENTS (3) GAS-IGNITION AND ADDITIVES

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JULY 2016 THROUGH DECEMBER 2016

SCHEDULE E5

	Estimated						
	Jul-16	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**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)	400	520	420	400	470	450	-23,012
16. UNIT COST ($/BBL)	68.57	69.14	69.90	70.69	71.47	72.16	55.52
17. AMOUNT ($)	27,429	35,951	29,356	28,274	33,591	32,470	-1,277,531
18. BURNED:							
19. UNITS (BBL)	400	520	420	400	470	450	3,192
20. UNIT COST ($/BBL)	126.96	126.29	125.76	125.27	124.71	124.18	696.40
21. AMOUNT ($)	50,783	65,671	52,820	50,109	58,613	55,882	2,222,900
22. ENDING INVENTORY:							
23. UNITS (BBL)	44,488	44,488	44,488	44,488	44,488	44,488	44,488
24. UNIT COST ($/BBL)	126.96	126.29	125.76	125.27	124.71	124.18	124.18
25. AMOUNT ($)	5,648,109	5,618,389	5,594,925	5,573,090	5,548,068	5,524,656	5,524,656
26. DAYS SUPPLY: NORMAL	3,030	3,030	3,030	3,030	2,963	2,990	-
27. DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6	
COAL							
28. PURCHASES:							
29. UNITS (TONS)	336,000	436,000	346,000	346,000	231,000	264,374	3,175,748
30. UNIT COST ($/TON)	73.69	72.36	74.32	74.66	72.79	75.22	75.03
31. AMOUNT ($)	24,760,936	31,550,730	25,714,613	25,831,313	16,814,325	19,885,177	238,288,641
32. BURNED:							
33. UNITS (TONS)	394,810	391,510	322,250	292,380	268,810	299,250	3,250,542
34. UNIT COST ($/TON)	77.82	79.53	78.46	76.37	73.20	76.98	79.66
35. AMOUNT ($)	30,722,489	31,137,807	25,283,910	22,328,492	19,677,285	23,037,483	258,935,180
36. ENDING INVENTORY:							
37. UNITS (TONS)	427,263	471,753	495,503	549,123	511,313	476,437	476,437
38. UNIT COST ($/TON)	70.82	65.44	63.57	64.07	63.69	62.09	62.09
39. AMOUNT ($)	30,256,921	30,873,840	31,499,029	35,180,904	32,563,305	29,582,477	29,582,477
40. DAYS SUPPLY:	35	43	51	59	52	48	-
NATURAL GAS							
41. PURCHASES:							
42. UNITS (MCF)	6,102,475	6,237,980	6,391,620	6,240,420	4,354,841	5,257,800	77,532,465
43. UNIT COST ($/MCF)	4.90	3.89	3.77	4.35	3.33	3.46	3.77
44. AMOUNT ($)	29,901,853	24,289,190	24,091,417	27,127,141	14,493,361	18,214,336	292,607,905
45. BURNED:							
46. UNITS (MCF)	5,940,860	6,237,980	6,391,620	6,240,420	4,646,670	5,257,800	77,575,520
47. UNIT COST ($/MCF)	4.81	3.89	3.76	4.33	3.26	3.41	3.74
48. AMOUNT ($)	28,582,681	24,263,108	24,001,165	27,003,431	15,141,954	17,924,252	290,482,817
49. ENDING INVENTORY:							
50. UNITS (MCF)	1,167,316	1,167,316	1,167,316	1,167,316	875,486	875,486	875,486
51. UNIT COST ($/MCF)	3.00	2.97	2.96	3.00	3.14	3.38	3.38
52. AMOUNT ($)	3,500,400	3,462,720	3,456,720	3,500,400	2,749,680	2,963,520	2,963,520
53. DAYS SUPPLY:	6	6	6	6	4	4	-
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 2016 THROUGH JUNE 2016

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-16	SEMINOLE	JURISD.	SCH. - D	287.3	0.0	287.3	1.869	2.138	5,370.05	6,141.23	234.17
	VARIOUS	JURISD.	SCH. - C	50.0	0.0	50.0	1.740	2.542	870.00	1,271.00	304.50
	VARIOUS	JURISD.	SCH. - CB	30,149.0	0.0	30,149.0	1.944	2.406	586,099.98	725,321.62	68,228.47
	VARIOUS	JURISD.	SCH. - MA	4,300.0	0.0	4,300.0	2.048	2.861	88,083.60	123,022.03	23,559.01
	TOTAL			**34,786.3**	**0.0**	**34,786.3**	**1.956**	**2.460**	**680,423.63**	**855,755.88**	**92,326.15**
ACTUAL											
Feb-16	SEMINOLE	JURISD.	SCH. - D	342.5	0.0	342.5	2.129	2.274	7,292.85	7,787.97	302.29
	VARIOUS	JURISD.	SCH. - C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - CB	7,220.0	0.0	7,220.0	2.094	2.482	151,171.08	179,213.00	12,004.68
	VARIOUS	JURISD.	SCH. - MA	486.0	0.0	486.0	1.250	1.824	6,076.81	8,862.64	1,617.33
	TOTAL			**8,048.5**	**0.0**	**8,048.5**	**2.044**	**2.434**	**164,540.74**	**195,863.61**	**13,924.30**
ACTUAL											
Mar-16	SEMINOLE	JURISD.	SCH. - D	477.0	0.0	477.0	1.929	2.122	9,200.77	10,120.85	257.78
	VARIOUS	JURISD.	SCH. - C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - CB	6,109.0	0.0	6,109.0	1.997	2.369	121,983.05	144,752.08	13,155.35
	VARIOUS	JURISD.	SCH. - MA	131.0	0.0	131.0	3.030	3.426	3,968.72	4,488.36	509.08
	TOTAL			**6,717.0**	**0.0**	**6,717.0**	**2.012**	**2.373**	**135,152.54**	**159,361.29**	**13,922.21**
ACTUAL											
Apr-16	SEMINOLE	JURISD.	SCH. - D	499.9	0.0	499.9	1.748	1.923	8,737.06	9,610.77	383.58
	VARIOUS	JURISD.	SCH. - C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - CB	11,079.0	0.0	11,079.0	1.817	2.199	201,332.23	243,676.97	20,741.92
	VARIOUS	JURISD.	SCH. - MA	400.0	0.0	400.0	1.611	2.282	6,442.55	9,126.55	1,837.40
	TOTAL			**11,978.9**	**0.0**	**11,978.9**	**1.807**	**2.191**	**216,511.84**	**262,414.29**	**22,962.90**
ACTUAL											
May-16	SEMINOLE	JURISD.	SCH. - D	569.2	0.0	569.2	1.777	1.955	10,115.57	11,127.13	244.13
	VARIOUS	JURISD.	SCH. - C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - CB	338.0	0.0	338.0	1.970	2.364	6,657.47	7,990.21	723.35
	VARIOUS	JURISD.	SCH. - MA	4,070.0	0.0	4,070.0	2.062	3.202	83,917.81	130,330.69	39,184.72
	TOTAL			**4,977.2**	**0.0**	**4,977.2**	**2.023**	**3.003**	**100,690.85**	**149,448.03**	**40,152.20**
ACTUAL											
Jun-16	SEMINOLE	JURISD.	SCH. - D	377.0	0.0	377.0	1.953	2.148	7,362.42	8,098.66	367.07
	VARIOUS	JURISD.	SCH. - C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - CB	1,461.0	0.0	1,461.0	2.641	3.159	38,581.30	46,158.93	4,047.44
	VARIOUS	JURISD.	SCH. - MA	1,310.0	0.0	1,310.0	1.993	2.863	26,105.59	37,506.31	8,601.56
	TOTAL			**3,148.0**	**0.0**	**3,148.0**	**2.289**	**2.915**	**72,049.31**	**91,763.90**	**13,016.07**

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2016 THROUGH DECEMBER 2016

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-16	SEMINOLE	JURISD.	SCH. - D	1,020.0	0.0	1,020.0	2.591	2.691	26,430.00	27,447.00	1,017.00
	VARIOUS	JURISD.	SCH. - C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - CB	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - MA	950.0	0.0	950.0	2.927	3.220	27,806.31	30,590.00	2,783.69
	TOTAL			**1,970.0**	**0.0**	**1,970.0**	**2.753**	**2.946**	**54,236.31**	**58,037.00**	**3,800.69**
ESTIMATED											
Aug-16	SEMINOLE	JURISD.	SCH. - D	1,010.0	0.0	1,010.0	2.639	2.740	26,650.00	27,676.00	1,026.00
	VARIOUS	JURISD.	SCH. - C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - CB	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - MA	1,130.0	0.0	1,130.0	2.671	2.938	30,178.80	33,200.00	3,021.20
	TOTAL			**2,140.0**	**0.0**	**2,140.0**	**2.656**	**2.845**	**56,828.80**	**60,876.00**	**4,047.20**
ESTIMATED											
Sep-16	SEMINOLE	JURISD.	SCH. - D	990.0	0.0	990.0	2.523	2.620	24,980.00	25,942.00	962.00
	VARIOUS	JURISD.	SCH. - C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - CB	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - MA	930.0	0.0	930.0	2.731	3.004	25,397.46	27,940.00	2,542.54
	TOTAL			**1,920.0**	**0.0**	**1,920.0**	**2.624**	**2.806**	**50,377.46**	**53,882.00**	**3,504.54**
ESTIMATED											
Oct-16	SEMINOLE	JURISD.	SCH. - D	730.0	0.0	730.0	2.601	2.702	18,990.00	19,721.00	731.00
	VARIOUS	JURISD.	SCH. - C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - CB	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - MA	900.0	0.0	900.0	2.733	3.007	24,597.54	27,060.00	2,462.46
	TOTAL			**1,630.0**	**0.0**	**1,630.0**	**2.674**	**2.870**	**43,587.54**	**46,781.00**	**3,193.46**
ESTIMATED											
Nov-16	SEMINOLE	JURISD.	SCH. - D	660.0	0.0	660.0	2.561	2.659	16,900.00	17,551.00	651.00
	VARIOUS	JURISD.	SCH. - C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - CB	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - MA	1,050.0	0.0	1,050.0	2.330	2.563	24,461.19	26,910.00	2,448.81
	TOTAL			**1,710.0**	**0.0**	**1,710.0**	**2.419**	**2.600**	**41,361.19**	**44,461.00**	**3,099.81**
ESTIMATED											
Dec-16	SEMINOLE	JURISD.	SCH. - D	580.0	0.0	580.0	2.667	2.770	15,470.00	16,065.00	595.00
	VARIOUS	JURISD.	SCH. - C	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - CB	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. - MA	2,090.0	0.0	2,090.0	1.155	1.271	24,143.04	26,560.00	2,416.96
	TOTAL			**2,670.0**	**0.0**	**2,670.0**	**1.484**	**1.596**	**39,613.04**	**42,625.00**	**3,011.96**
TOTAL	SEMINOLE	JURISD.	SCH. - D	7,542.9	0.0	7,542.9	2.353	2.483	177,498.72	187,288.61	6,771.02
Jan-16	VARIOUS	JURISD.	SCH. - C	50.0	0.0	50.0	1.740	2.542	870.00	1,271.00	304.50
THRU	VARIOUS	JURISD.	SCH. - CB	56,356.0	0.0	56,356.0	1.962	2.390	1,105,825.11	1,347,112.81	118,901.21
Dec-16	VARIOUS	JURISD.	SCH. - MA	17,747.0	0.0	17,747.0	2.092	2.736	371,179.42	485,596.58	90,984.76
	TOTAL			**81,695.9**	**0.0**	**81,695.9**	**2.026**	**2.474**	**1,655,373.25**	**2,021,269.00**	**216,961.49**

TAMPA ELECTRIC COMPANY
PURCHASED POWER **SCHEDULE E7**
(EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES)
ACTUAL FOR THE PERIOD: JANUARY 2016 THROUGH JUNE 2016

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH	MWH		CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILITIES	FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
ACTUAL Jan-16									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	702,747.97
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	(6,187.09)
	PASCO COGEN	SCH. - D	7,733.0	0.0	0.0	7,733.0	4.089	4.089	316,177.52
	DUKE ENERGY	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	OATT	635.0	0.0	0.0	635.0	1.866	1.866	11,848.18
	TOTAL		**8,368.0**	**0.0**	**0.0**	**8,368.0**	**12.244**	**12.244**	**1,024,586.58**
ACTUAL Feb-16									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	3,348.0	0.0	0.0	3,348.0	3.553	3.553	118,951.50
	DUKE ENERGY	SCH. - D	171,160.0	0.0	0.0	171,160.0	1.692	1.692	2,896,486.40
	VARIOUS	OATT	1,349.0	0.0	0.0	1,349.0	2.141	2.141	28,880.68
	TOTAL		**175,857.0**	**0.0**	**0.0**	**175,857.0**	**1.731**	**1.731**	**3,044,318.58**
ACTUAL Mar-16									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	11,313.0	0.0	0.0	11,313.0	3.295	3.295	372,736.79
	DUKE ENERGY	SCH. - D	160,950.0	0.0	0.0	160,950.0	1.527	1.527	2,458,092.20
	VARIOUS	OATT	1,306.0	0.0	0.0	1,306.0	2.109	2.109	27,545.26
	TOTAL		**173,569.0**	**0.0**	**0.0**	**173,569.0**	**1.647**	**1.647**	**2,858,374.25**
ACTUAL Apr-16									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	1,755.0	0.0	0.0	1,755.0	4.451	4.451	78,110.97
	PASCO COGEN	SCH. - D	11,647.0	0.0	0.0	11,647.0	3.513	3.513	409,117.83
	DUKE ENERGY	SCH. - D	116,360.0	0.0	0.0	116,360.0	1.772	1.772	2,062,121.70
	VARIOUS	OATT	38.0	0.0	0.0	38.0	5.869	5.869	2,230.31
	TOTAL		**129,800.0**	**0.0**	**0.0**	**129,800.0**	**1.966**	**1.966**	**2,551,580.81**
ACTUAL May-16									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	18,536.0	0.0	0.0	18,536.0	3.545	3.545	657,047.85
	DUKE ENERGY	SCH. - D	163,120.0	0.0	0.0	163,120.0	1.601	1.601	2,611,946.39
	EXGEN	SCH. - JCBO	76,798.0	0.0	0.0	76,798.0	1.707	1.707	1,311,105.56
	FPL	SCH. - JCBO	49,955.0	0.0	0.0	49,955.0	1.825	1.825	911,541.50
	VARIOUS	OATT	979.0	0.0	0.0	979.0	1.944	1.944	19,036.29
	TOTAL		**309,388.0**	**0.0**	**0.0**	**309,388.0**	**1.781**	**1.781**	**5,510,677.59**
ACTUAL Jun-16									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	4,329.0	0.0	0.0	4,329.0	5.825	5.825	252,169.32
	PASCO COGEN	SCH. - D	26,364.0	0.0	0.0	26,364.0	4.309	4.309	1,136,009.08
	DUKE ENERGY	SCH. - D	169,419.0	0.0	0.0	169,419.0	2.037	2.037	3,451,780.41
	EXGEN	SCH. - JCBO	78,525.0	0.0	0.0	78,525.0	2.160	2.160	1,695,943.85
	FPL	SCH. - JCBO	29,880.0	0.0	0.0	29,880.0	2.323	2.323	694,065.30
	VARIOUS	OATT	925.0	0.0	0.0	925.0	3.186	3.186	29,474.67
	TOTAL		**309,442.0**	**0.0**	**0.0**	**309,442.0**	**2.346**	**2.346**	**7,259,442.63**

TAMPA ELECTRIC COMPANY
PURCHASED POWER
(EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES)
ESTIMATED FOR THE PERIOD: JULY 2016 THROUGH DECEMBER 2016

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
ESTIMATED Jul-16									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	6,280.0	0.0	0.0	6,280.0	4.536	4.536	284,860.00
	DUKE ENERGY	SCH. - D	150,800.0	0.0	0.0	150,800.0	3.529	3.529	5,322,090.00
	EXGEN	SCH. - JCBO	40,750.0	0.0	0.0	40,750.0	2.618	2.618	1,066,650.00
	FPL	SCH. - JCBO	33,210.0	0.0	0.0	33,210.0	2.540	2.540	843,600.00
	TOTAL		**231,040.0**	**0.0**	**0.0**	**231,040.0**	**3.254**	**3.254**	**7,517,200.00**
ESTIMATED Aug-16									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	650.0	0.0	0.0	650.0	5.886	5.886	38,260.00
	PASCO COGEN	SCH. - D	6,030.0	0.0	0.0	6,030.0	3.777	3.777	227,760.00
	DUKE ENERGY	SCH. - D	167,680.0	0.0	0.0	167,680.0	2.878	2.878	4,825,150.00
	EXGEN	SCH. - JCBO	35,400.0	0.0	0.0	35,400.0	2.595	2.595	918,750.00
	FPL	SCH. - JCBO	31,370.0	0.0	0.0	31,370.0	2.472	2.472	775,620.00
	TOTAL		**241,130.0**	**0.0**	**0.0**	**241,130.0**	**2.814**	**2.814**	**6,785,540.00**
ESTIMATED Sep-16									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	3,400.0	0.0	0.0	3,400.0	3.698	3.698	125,740.00
	DUKE ENERGY	SCH. - D	159,280.0	0.0	0.0	159,280.0	2.788	2.788	4,440,330.00
	EXGEN	SCH. - JCBO	29,470.0	0.0	0.0	29,470.0	2.608	2.608	768,470.00
	FPL	SCH. - JCBO	23,230.0	0.0	0.0	23,230.0	2.482	2.482	576,520.00
	TOTAL		**215,380.0**	**0.0**	**0.0**	**215,380.0**	**2.744**	**2.744**	**5,911,060.00**
ESTIMATED Oct-16									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	1,960.0	0.0	0.0	1,960.0	4.168	4.168	81,690.00
	DUKE ENERGY	SCH. - D	49,880.0	0.0	0.0	49,880.0	3.216	3.216	1,604,060.00
	EXGEN	SCH. - JCBO	31,930.0	0.0	0.0	31,930.0	2.618	2.618	835,870.00
	FPL	SCH. - JCBO	15,080.0	0.0	0.0	15,080.0	2.546	2.546	383,970.00
	TOTAL		**98,850.0**	**0.0**	**0.0**	**98,850.0**	**2.939**	**2.939**	**2,905,590.00**
ESTIMATED Nov-16									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	PASCO COGEN	SCH. - D	1,590.0	0.0	0.0	1,590.0	3.381	3.381	53,760.00
	DUKE ENERGY	SCH. - D	60,760.0	0.0	0.0	60,760.0	2.484	2.484	1,509,540.00
	EXGEN	SCH. - JCBO	3,340.0	0.0	0.0	3,340.0	3.256	3.256	108,760.00
	FPL	SCH. - JCBO	13,300.0	0.0	0.0	13,300.0	2.556	2.556	339,940.00
	TOTAL		**78,990.0**	**0.0**	**0.0**	**78,990.0**	**2.547**	**2.547**	**2,012,000.00**
ESTIMATED Dec-16									
	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	CALPINE	SCH. - D	870.0	0.0	0.0	870.0	7.614	7.614	66,240.00
	PASCO COGEN	SCH. - D	1,900.0	0.0	0.0	1,900.0	3.438	3.438	65,330.00
	DUKE ENERGY	SCH. - D	26,580.0	0.0	0.0	26,580.0	2.829	2.829	752,050.00
	EXGEN	SCH. - JCBO	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	FPL	SCH. - JCBO	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**29,350.0**	**0.0**	**0.0**	**29,350.0**	**3.011**	**3.011**	**883,620.00**
TOTAL									
Jan-16	OLEANDER	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	702,747.97
THRU	CALPINE	SCH. - D	7,604.0	0.0	0.0	7,604.0	5.636	5.636	428,593.20
Dec-16	PASCO COGEN	SCH. - D	100,101.0	0.0	0.0	100,101.0	3.845	3.845	3,849,180.57
	DUKE ENERGY	SCH. - D	1,395,989.0	0.0	0.0	1,395,989.0	2.288	2.288	31,933,647.10
	EXGEN	SCH. - JCBO	296,213.0	0.0	0.0	296,213.0	2.264	2.264	6,705,549.41
	FPL	SCH. - JCBO	196,025.0	0.0	0.0	196,025.0	2.309	2.309	4,525,256.80
	VARIOUS	OATT	5,232.0	0.0	0.0	5,232.0	2.275	2.275	119,015.39
	TOTAL		**2,001,164.0**	**0.0**	**0.0**	**2,001,164.0**	**2.412**	**2.412**	**48,263,990.44**

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2016 THROUGH DECEMBER 2016

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 Jan-16	VARIOUS	CO-GEN.							
		AS AVAIL.	18,943.0	0.0	0.0	18,943.0	1.992	1.992	377,381.48
	TOTAL		18,943.0	0.0	0.0	18,943.0	1.992	1.992	377,381.48
ACTUAL Feb-16	VARIOUS	CO-GEN.							
		AS AVAIL.	15,799.0	0.0	0.0	15,799.0	2.324	2.324	367,240.31
	TOTAL		15,799.0	0.0	0.0	15,799.0	2.324	2.324	367,240.31
ACTUAL Mar-16	VARIOUS	CO-GEN.							
		AS AVAIL.	22,287.0	0.0	0.0	22,287.0	2.097	2.097	467,423.28
	TOTAL		22,287.0	0.0	0.0	22,287.0	2.097	2.097	467,423.28
ACTUAL Apr-16	VARIOUS	CO-GEN.							
		AS AVAIL.	28,100.0	0.0	0.0	28,100.0	2.017	2.017	566,878.53
	TOTAL		28,100.0	0.0	0.0	28,100.0	2.017	2.017	566,878.53
ACTUAL May-16	VARIOUS	CO-GEN.							
		AS AVAIL.	22,443.0	0.0	0.0	22,443.0	1.987	1.987	445,937.02
	TOTAL		22,443.0	0.0	0.0	22,443.0	1.987	1.987	445,937.02
ACTUAL Jun-16	VARIOUS	CO-GEN.							
		AS AVAIL.	19,079.0	0.0	0.0	19,079.0	2.162	2.162	412,546.37
	TOTAL		19,079.0	0.0	0.0	19,079.0	2.162	2.162	412,546.37
ESTIMATED Jul-16	VARIOUS	CO-GEN.							
		AS AVAIL.	7,500.0	0.0	0.0	7,500.0	4.676	4.676	350,710.00
	TOTAL		7,500.0	0.0	0.0	7,500.0	4.676	4.676	350,710.00
ESTIMATED Aug-16	VARIOUS	CO-GEN.							
		AS AVAIL.	7,570.0	0.0	0.0	7,570.0	2.493	2.493	188,720.00
	TOTAL		7,570.0	0.0	0.0	7,570.0	2.493	2.493	188,720.00
ESTIMATED Sep-16	VARIOUS	CO-GEN.							
		AS AVAIL.	7,470.0	0.0	0.0	7,470.0	2.192	2.192	163,740.00
	TOTAL		7,470.0	0.0	0.0	7,470.0	2.192	2.192	163,740.00
ESTIMATED Oct-16	VARIOUS	CO-GEN.							
		AS AVAIL.	7,530.0	0.0	0.0	7,530.0	1.894	1.894	142,640.00
	TOTAL		7,530.0	0.0	0.0	7,530.0	1.894	1.894	142,640.00
ESTIMATED Nov-16	VARIOUS	CO-GEN.							
		AS AVAIL.	7,570.0	0.0	0.0	7,570.0	2.313	2.313	175,110.00
	TOTAL		7,570.0	0.0	0.0	7,570.0	2.313	2.313	175,110.00
ESTIMATED Dec-16	VARIOUS	CO-GEN.							
		AS AVAIL.	7,420.0	0.0	0.0	7,420.0	1.804	1.804	133,840.00
	TOTAL		7,420.0	0.0	0.0	7,420.0	1.804	1.804	133,840.00
TOTAL Jan-16 THRU Dec-16	VARIOUS	CO-GEN.							
		AS AVAIL.	171,711.0	0.0	0.0	171,711.0	2.208	2.208	3,792,166.99
	TOTAL		171,711.0	0.0	0.0	171,711.0	2.208	2.208	3,792,166.99

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2016 THROUGH DECEMBER 2016

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) ($000)	FUEL SAVINGS (9B)-(8)
ACTUAL	VARIOUS	SCH. - REB	0.0	0.0	0.0	0.000	0.00	0.000	0.00	0.00
Jan-16	VARIOUS	SCH. - J	8,888.0	0.0	8,888.0	2.650	235,532.00	2.761	245,408.90	9,876.90
	TOTAL		**8,888.0**	**0.0**	**8,888.0**	**2.650**	**235,532.00**	**2.761**	**245,408.90**	**9,876.90**
ACTUAL	VARIOUS	SCH. - REB	1,362.0	0.0	1,362.0	1.957	26,656.00	2.201	29,981.77	3,325.77
Feb-16	VARIOUS	SCH. - J	1,959.0	0.0	1,959.0	2.305	45,164.00	2.685	52,590.48	7,426.48
	TOTAL		**3,321.0**	**0.0**	**3,321.0**	**2.163**	**71,820.00**	**2.486**	**82,572.25**	**10,752.25**
ACTUAL	VARIOUS	SCH. - REB	0.0	0.0	0.0	0.000	0.00	0.000	0.00	0.00
Mar-16	VARIOUS	SCH. - J	11,106.0	0.0	11,106.0	1.438	159,719.98	2.370	263,185.93	103,465.95
	TOTAL		**11,106.0**	**0.0**	**11,106.0**	**1.438**	**159,719.98**	**2.370**	**263,185.93**	**103,465.95**
ACTUAL	VARIOUS	SCH. - REB	0.0	0.0	0.0	0.000	0.00	0.000	0.00	0.00
Apr-16	VARIOUS	SCH. - J	11,444.0	0.0	11,444.0	3.387	387,642.25	3.751	429,319.43	41,677.18
	TOTAL		**11,444.0**	**0.0**	**11,444.0**	**3.387**	**387,642.25**	**3.751**	**429,319.43**	**41,677.18**
ACTUAL	VARIOUS	SCH. - REB	10.0	0.0	10.0	2.100	210.00	2.254	225.40	15.40
May-16	VARIOUS	SCH. - J	15,458.0	0.0	15,458.0	2.379	367,704.45	2.929	452,733.64	85,029.19
	TOTAL		**15,468.0**	**0.0**	**15,468.0**	**2.379**	**367,914.45**	**2.928**	**452,959.04**	**85,044.59**
ACTUAL	VARIOUS	SCH. - REB	750.0	0.0	750.0	2.217	16,625.00	2.733	20,498.30	3,873.30
Jun-16	VARIOUS	SCH. - J	12,530.0	0.0	12,530.0	4.093	512,823.00	4.689	587,569.51	74,746.51
	TOTAL		**13,280.0**	**0.0**	**13,280.0**	**3.987**	**529,448.00**	**4.579**	**608,067.81**	**78,619.81**
ESTIMATED	VARIOUS	ECONOMY	25,610.0	0.0	25,610.0	3.234	828,180.00	3.590	919,350.00	91,170.00
Jul-16	**TOTAL**		**25,610.0**	**0.0**	**25,610.0**	**3.234**	**828,180.00**	**3.590**	**919,350.00**	**91,170.00**
ESTIMATED	VARIOUS	ECONOMY	27,620.0	0.0	27,620.0	3.312	914,820.00	3.331	920,050.00	5,230.00
Aug-16	**TOTAL**		**27,620.0**	**0.0**	**27,620.0**	**3.312**	**914,820.00**	**3.331**	**920,050.00**	**5,230.00**
ESTIMATED	VARIOUS	ECONOMY	23,740.0	0.0	23,740.0	2.986	708,960.00	3.104	736,850.00	27,890.00
Sep-16	**TOTAL**		**23,740.0**	**0.0**	**23,740.0**	**2.986**	**708,960.00**	**3.104**	**736,850.00**	**27,890.00**
ESTIMATED	VARIOUS	ECONOMY	23,860.0	0.0	23,860.0	3.015	719,370.00	3.015	719,370.00	0.00
Oct-16	**TOTAL**		**23,860.0**	**0.0**	**23,860.0**	**3.015**	**719,370.00**	**3.015**	**719,370.00**	**0.00**
ESTIMATED	VARIOUS	ECONOMY	26,930.0	0.0	26,930.0	2.772	746,570.00	2.772	746,570.00	0.00
Nov-16	**TOTAL**		**26,930.0**	**0.0**	**26,930.0**	**2.772**	**746,570.00**	**2.772**	**746,570.00**	**0.00**
ESTIMATED	VARIOUS	ECONOMY	24,140.0	0.0	24,140.0	3.326	802,800.00	3.354	809,740.00	6,940.00
Dec-16	**TOTAL**		**24,140.0**	**0.0**	**24,140.0**	**3.326**	**802,800.00**	**3.354**	**809,740.00**	**6,940.00**
TOTAL	VARIOUS	SCH. - REB	2,122.0	0.0	2,122.0	2.050	43,491.00	2.390	50,705.47	7,214.47
Jan-16	VARIOUS	SCH. - J	61,385.0	0.0	61,385.0	2.783	1,708,585.68	3.308	2,030,807.89	322,222.21
THRU	VARIOUS	ECONOMY	151,900.0	0.0	151,900.0	3.108	4,720,700.00	3.194	4,851,930.00	131,230.00
Dec-16	**TOTAL**		**215,407.0**	**0.0**	**215,407.0**	**3.005**	**6,472,776.68**	**3.219**	**6,933,443.36**	**460,666.68**

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 2

CAPACITY COST RECOVERY

ACTUAL / ESTIMATED

JANUARY 2016 THROUGH DECEMBER 2016

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY
CALCULATION OF THE CURRENT (ACTUAL/ESTIMATED) PERIOD TRUE-UP
JANUARY 2016 THROUGH DECEMBER 2016

1.	FINAL OVER/(UNDER) RECOVERY FOR JANUARY 2015 THROUGH DECEMBER 2015	($2,449,694)
2.	ACTUAL/ESTIMATED OVER/(UNDER) RECOVERY FOR THE CURRENT PERIOD JANUARY 2016 THROUGH DECEMBER 2016	(536,366)
3.	CURRENT PERIOD TRUE-UP AMOUNT TO BE REFUNDED/(RECOVERED) IN THE PROJECTION PERIOD JANUARY 2017 THROUGH DECEMBER 2017	($2,986,060)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
JANUARY 2016 THROUGH DECEMBER 2016

	Actual Jan-16	Actual Feb-16	Actual Mar-16	Actual Apr-16	Actual May-16	Actual Jun-16	Estimated Jul-16	Estimated Aug-16	Estimated Sep-16	Estimated Oct-16	Estimated Nov-16	Estimated Dec-16	Total
1 UNIT POWER CAPACITY CHARGES	1,231,451	2,244,153	2,242,223	2,252,253	3,205,047	4,476,611	3,382,070	3,382,070	3,382,070	3,382,070	3,382,070	2,241,570	34,803,658
2 CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0	0	0	0	0	0	0	0	0	0
3 (UNIT POWER CAPACITY REVENUES)	(188,374)	(67,143)	(45,918)	(75,099)	(17,741)	(27,459)	(70,289)	(70,289)	(70,289)	(70,289)	(70,289)	(70,290)	(843,469)
4 TOTAL CAPACITY DOLLARS	1,043,077	2,177,010	2,196,305	2,177,154	3,187,306	4,449,152	3,311,781	3,311,781	3,311,781	3,311,781	3,311,781	2,171,280	33,960,189
5 SEPARATION FACTOR	0.9958367	0.9958367	0.9958367	0.9958367	0.9958367	0.9958367	0.9958367	0.9958367	0.9958367	0.9958367	0.9958367	0.9958367	
6 JURISDICTIONAL CAPACITY DOLLARS	1,038,734	2,167,946	2,187,161	2,168,090	3,174,037	4,430,629	3,297,993	3,297,993	3,297,993	3,297,993	3,297,993	2,162,240	33,818,802
7 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	2,237,815	2,089,102	1,963,140	2,085,524	2,287,751	2,700,140	3,212,719	3,220,168	3,284,771	2,944,616	2,542,454	2,518,089	31,086,289
8 PRIOR PERIOD TRUE-UP PROVISION	183,647	183,647	183,647	183,647	183,647	183,647	183,647	183,647	183,647	183,647	183,647	183,652	2,203,769
9 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	2,421,462	2,272,749	2,146,787	2,269,171	2,471,398	2,883,787	3,396,366	3,403,815	3,468,418	3,128,263	2,726,101	2,701,741	33,290,058
10 TRUE-UP PROVISION FOR MONTH OVER/(UNDER) RECOVERY (Line 9 - Line 6)	1,382,728	104,803	(40,374)	101,081	(702,639)	(1,546,842)	98,373	105,822	170,425	(169,730)	(571,892)	539,501	(528,744)
11 INTEREST PROVISION FOR MONTH	117	311	275	201	40	(402)	(669)	(695)	(1,088)	(1,611)	(1,983)	(2,118)	(7,622)
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	(245,925)	953,273	874,740	650,994	568,629	(317,617)	(2,048,508)	(2,134,451)	(2,212,971)	(2,227,281)	(2,582,269)	(3,339,791)	(245,925)
14 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS MONTH	(183,647)	(183,647)	(183,647)	(183,647)	(183,647)	(183,647)	(183,647)	(183,647)	(183,647)	(183,647)	(183,647)	(183,652)	(2,203,769)
15 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 10 - 14)	**953,273**	**874,740**	**650,994**	**568,629**	**(317,617)**	**(2,048,508)**	**(2,134,451)**	**(2,212,971)**	**(2,227,281)**	**(2,582,269)**	**(3,339,791)**	**(2,986,060)**	**(2,986,060)**

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT
JANUARY 2016 THROUGH DECEMBER 2016

	Actual Jan-16	Actual Feb-16	Actual Mar-16	Actual Apr-16	Actual May-16	Actual Jun-16	Estimated Jul-16	Estimated Aug-16	Estimated Sep-16	Estimated Oct-16	Estimated Nov-16	Estimated Dec-16	Total
1 BEGINNING TRUE-UP AMOUNT	(245,925)	953,273	874,740	650,994	568,629	(317,617)	(2,048,508)	(2,134,451)	(2,212,971)	(2,227,281)	(2,582,269)	(3,339,791)	(245,925)
2 ENDING TRUE-UP AMOUNT BEFORE INTEREST	953,156	874,429	650,719	568,428	(317,657)	(2,048,106)	(2,133,782)	(2,212,276)	(2,226,193)	(2,580,658)	(3,337,808)	(2,983,942)	(2,978,438)
3 TOTAL BEGINNING & ENDING TRUE-UP AMT. (LINE 1 + LINE 2)	707,231	1,827,702	1,525,459	1,219,422	250,972	(2,365,723)	(4,182,290)	(4,346,727)	(4,439,164)	(4,807,939)	(5,920,077)	(6,323,733)	(3,224,363)
4 AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	353,616	913,851	762,730	609,711	125,486	(1,182,862)	(2,091,145)	(2,173,364)	(2,219,582)	(2,403,970)	(2,960,039)	(3,161,867)	(1,612,182)
5 INTEREST RATE % - 1ST DAY OF MONTH	0.400	0.400	0.420	0.440	0.340	0.430	0.380	0.380	0.380	0.800	0.800	0.800	NA
6 INTEREST RATE % - 1ST DAY OF NEXT MONTH	0.400	0.420	0.440	0.340	0.430	0.380	0.380	0.380	0.800	0.800	0.800	0.800	NA
7 TOTAL (LINE 5 + LINE 6)	0.800	0.820	0.860	0.780	0.770	0.810	0.760	0.760	1.180	1.600	1.600	1.600	NA
8 AVERAGE INTEREST RATE % (50% OF LINE 7)	0.400	0.410	0.430	0.390	0.385	0.405	0.380	0.380	0.590	0.800	0.800	0.800	NA
9 MONTHLY AVERAGE INTEREST RATE % (LINE 8/12)	0.033	0.034	0.036	0.033	0.032	0.034	0.032	0.032	0.049	0.067	0.067	0.067	NA
10 INTEREST PROVISION (LINE 4 X LINE 9)	117	311	275	201	40	(402)	(669)	(695)	(1,088)	(1,611)	(1,983)	(2,118)	(7,622)

TAMPA ELECTRIC COMPANY
CAPACITY COSTS
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2016 THROUGH DECEMBER 2016

SCHEDULE E12

CONTRACT	TERM START	TERM END	CONTRACT TYPE
DUKE ENERGY FLORIDA	2/1/2016	2/28/2017	LT
CALPINE	11/1/2011	12/31/2016	LT
PASCO COGEN LTD	1/1/2009	12/31/2018	LT
SEMINOLE ELECTRIC **	6/1/1992	----------	LT
EXELON GENERATION COMPANY, LLC	5/1/2016	11/30/2016	ST
FLORIDA POWER & LIGHT COMPANY	5/1/2016	11/30/2016	ST

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
DUKE ENERGY FLORIDA	-	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
CALPINE	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
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	0.8	1.1	1.6	1.3	1.2	1.3	1.5	1.7	1.4	1.4	1.2	1.2
EXELON GENERATION COMPANY, LLC	-	-	-	-	150.0	150.0	150.0	150.0	150.0	150.0	150.0	-
FLORIDA POWER & LIGHT COMPANY	-	-	-	-	100.0	100.0	100.0	100.0	100.0	100.0	100.0	-

REDACTED

TAMPA ELECTRIC COMPANY
CAPACITY COSTS
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2016 THROUGH DECEMBER 2016

SCHEDULE E12

CAPACITY	ACT JANUARY ($)	ACT FEBRUARY ($)	ACT MARCH ($)	ACT APRIL ($)	ACT MAY ($)	ACT JUNE ($)	EST JULY ($)	EST AUGUST ($)	EST SEPTEMBER ($)	EST OCTOBER ($)	EST NOVEMBER ($)	EST DECEMBER ($)	TOTAL ($)
CALPINE - D													
DUKE ENERGY FLORIDA - D													
PASCO COGEN LTD - D													
FLORIDA POWER & LIGHT													
DUKE ENERGY FLORIDA													
JACKSONVILLE ELECTRIC AUTHORITY													
FLORIDA POWER & LIGHT - JCBO													
EXGEN (EXELON) - JCBO													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
DUKE ENERGY FLORIDA - CB													
FLORIDA POWER & LIGHT - CB													
ORLANDO UTILITIES - CB													
REEDY CREEK - CB													
SEMINOLE ELECTRIC - CB													
THE ENERGY AUTHORITY - CB													
VARIOUS - MA													
EXGEN - MA													
THE ENERGY AUTHORITY - MA													
MERCURIA AMERICA - MA													
MORGAN STANLEY - MA													
SOUTHERN CO - MA													
NEW SMYRNA BEACH - MA													
EDF TRADING - MA													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	$ 1,043,077	$ 2,177,010	$ 2,196,305	$ 2,177,154	$ 3,187,306	$ 4,449,152	$ 3,311,781	$ 3,311,781	$ 3,311,781	$ 3,311,781	$ 3,311,781	$ 2,171,280	$ 33,960,189
TOTAL CAPACITY	$ 1,043,077	$ 2,177,010	$ 2,196,305	$ 2,177,154	$ 3,187,306	$ 4,449,152	$ 3,311,781	$ 3,311,781	$ 3,311,781	$ 3,311,781	$ 3,311,781	$ 2,171,280	$ 33,960,189

Docket No. 160001-EI
Exhibit No. PAR-2
Document No. 2, Page 5 of 5

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 3

CAPITAL PROJECTS APPROVED FOR

FUEL CLAUSE RECOVERY

JANUARY 2016 - DECEMBER 2016

POLK 1 IGNITION CONVERSION
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2016 THROUGH DECEMBER 2016

		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	$ 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	$ 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	$ 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%	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	269,225	269,225	269,225	269,225	269,225	269,225	3,230,701
10	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
11	BEGINNING BALANCE DEPRECIATION	8,067,199	8,336,424	8,605,649	8,874,874	9,144,099	9,413,324	9,682,549	9,951,774	10,220,999	10,490,224	10,759,449	11,028,674	8,067,199
12	ENDING BALANCE DEPRECIATION	8,336,424	8,605,649	8,874,874	9,144,099	9,413,324	9,682,549	9,951,774	10,220,999	10,490,224	10,759,449	11,028,674	11,297,899	11,297,899
13														
14														
15	ENDING NET INVESTMENT	7,807,527	7,538,302	7,269,077	6,999,852	6,730,627	6,461,402	6,192,177	5,922,952	5,653,726	5,384,501	5,115,276	4,846,051	4,846,051
16														
17														
18	AVERAGE INVESTMENT	7,942,140	7,672,914	7,403,689	7,134,464	6,865,239	6,596,014	$ 6,326,789	$ 6,057,564	$ 5,788,339	$ 5,519,114	$ 5,249,889	$ 4,980,664	
19	ALLOWED EQUITY RETURN	.36016%	.36016%	.36016%	.36016%	.36016%	.36016%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	
20	EQUITY COMPONENT AFTER-TAX	28,604	27,635	26,665	25,695	24,726	23,756	22,699	21,734	20,768	19,802	18,836	17,870	278,790
21	CONVERSION TO PRE-TAX	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	
22	EQUITY COMPONENT PRE-TAX	46,687	45,106	43,523	41,939	40,358	38,775	37,049	35,474	33,898	32,321	30,744	29,167	455,041
23														
24	ALLOWED DEBT RETURN	.16226%	.16226%	.16226%	.16226%	.16226%	.16226%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	
25	DEBT COMPONENT	12,887	12,450	12,013	11,576	11,139	10,702	9,989	9,564	9,139	8,714	8,289	7,864	124,326
26														
27	TOTAL RETURN REQUIREMENTS	59,574	57,556	55,536	28,240	51,497	49,477	47,038	45,038	43,037	41,035	39,033	37,031	554,092
28														
29	TOTAL DEPRECIATION & RETURN	328,799	326,781	350,036	297,465	320,722	318,702	316,263	314,263	312,262	310,260	308,258	306,256	3,810,068
30														
31	ESTIMATED FUEL SAVINGS	3,560	3,040,230	1,163,516	2,435,447	3,234,901	6,724,034	$394,696	$1,247,835	$924,664	$211,200	$1,033,200	$529,461	$20,942,744
32	TOTAL DEPRECIATION & RETURN	328,799	326,781	350,036	297,465	320,722	318,702	$316,263	$314,263	$312,262	$310,260	$308,258	$306,256	$3,810,068
33	NET BENEFIT (COST) TO RATEPAYER	(325,239)	2,713,449	838,755	2,112,707	2,914,179	6,405,332	$78,433	$933,572	$612,402	($99,060)	$724,942	$223,205	$17,132,676
34														

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 9.0013% (EQUITY 7.0542% , DEBT 1.9471%). RATES ARE BASED ON THE MAY 2015 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
37 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JULY - DECEMBER USING AN ANNUAL RATE OF 8.9219% (EQUITY 7.0273% , DEBT 1.8946%). RATES ARE BASED ON THE MAY 2016 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
38 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 38.575%
39 ZERO PROJECTED GENERATION RESULTS IN ZERO ESTIMATED FUEL SAVINGS FOR THAT MONTH.

BIG BEND UNITS 1-4 IGNITERS CONVERSION TO NATURAL GAS
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2016 THROUGH DECEMBER 2016

		ACTUAL JANUARY	ACTUAL FEBRUARY	ACTUAL MARCH	ACTUAL APRIL	ACTUAL MAY	ACTUAL JUNE	PROJECTED JULY	PROJECTED AUGUST	PROJECTED SEPTEMBER	PROJECTED OCTOBER	PROJECTED NOVEMBER	PROJECTED DECEMBER	TOTAL
1	BEGINNING BALANCE	20,822,967	20,905,471	20,905,446	20,909,208	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,910,348	20,822,967
2	ADD INVESTMENT	76,012	(21,560)	-	-	-	-	-	-	-	-	-	-	54,452
2a	ADD INVESTMENT: Big Bend Unit 4 (May 2015)	-	(19,487)	-	-	-	-	-	-	-	-	-	-	(19,487)
2b	ADD INVESTMENT: Big Bend Unit 2 (June 2015)	(4,229)	38,978	-	-	-	-	-	-	-	-	-	-	34,749
2c	ADD INVESTMENT: Big Bend Unit 1	10,720	2,044	3,762	1,140	-	-	-	-	-	-	-	-	17,667
3	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
4	ENDING BALANCE	20,905,471	20,905,446	20,909,208	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	20,864,219	20,905,458	20,907,327	20,909,778	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	347,737	348,424	348,455	348,496	348,506	348,506	348,506	348,506	348,506	348,506	348,506	348,506	4,181,159
10	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
11	BEGINNING BALANCE DEPRECIATION	2,550,481	2,898,218	3,246,643	3,595,098	3,943,594	4,292,100	4,640,606	4,989,112	5,337,618	5,686,123	6,034,629	6,383,135	2,550,481
12	ENDING BALANCE DEPRECIATION	2,898,218	3,246,643	3,595,098	3,943,594	4,292,100	4,640,606	4,989,112	5,337,618	5,686,123	6,034,629	6,383,135	6,731,641	6,731,641
13														
14														
15	ENDING NET INVESTMENT	18,007,252	17,658,803	17,314,110	16,966,754	16,618,248	16,269,742	15,921,236	15,572,731	15,224,225	14,875,719	14,527,213	14,178,707	14,178,707
16														
17														
18	AVERAGE INVESTMENT	$18,139,869	$17,833,028	$17,486,456	$17,140,432	$16,792,501	$16,443,995	$16,095,489	$15,746,983	$15,398,478	$15,049,972	$14,701,466	$14,352,960	
19	ALLOWED EQUITY RETURN	.36016%	.36016%	.36016%	.36016%	.36016%	.36016%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	
20	EQUITY COMPONENT AFTER-TAX	65,333	64,227	62,979	61,733	60,480	59,225	57,748	56,498	55,247	53,997	52,746	51,496	701,709
21	CONVERSION TO PRE-TAX	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	
22	EQUITY COMPONENT PRE-TAX	$106,637	$104,831	$102,794	$100,761	$98,715	$96,667	$94,256	$92,216	$90,174	$88,134	$86,092	$84,052	$1,145,329
23														
24	ALLOWED DEBT RETURN	.16226%	.16226%	.16226%	.16226%	.16226%	.16226%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	
25	DEBT COMPONENT	$29,433	$28,935	$28,373	$27,811	$27,247	$26,681	$25,412	$24,862	$24,312	$23,761	$23,211	$22,661	$312,699
26														
27	TOTAL RETURN REQUIREMENTS	$136,070	$133,766	$131,167	$128,572	$125,962	$123,348	$119,668	$117,078	$114,486	$111,895	$109,303	$106,713	$1,458,028
28	PRIOR MONTH TRUE-UP													-
29	TOTAL DEPRECIATION & RETURN	$483,807	$482,190	$479,622	$477,068	$474,468	$471,854	$468,174	$465,584	$462,992	$460,401	$457,809	$455,219	$5,639,187
30														
31	ESTIMATED FUEL SAVINGS	$675,815	$855,095	$572,690	$539,935	$432,312	$1,551,829	$432,568	$283,992	$460,859	$349,927	$560,638	$376,471	$7,092,131
32	TOTAL DEPRECIATION & RETURN	$483,807	$482,190	$479,622	$477,068	$474,468	$471,854	$468,174	$465,584	$462,992	$460,401	$457,809	$455,219	$5,639,187
33	NET BENEFIT (COST) TO RATEPAYER	$192,008	$372,905	$93,068	$62,867	($42,155)	$1,079,976	($35,606)	($181,592)	($2,133)	($110,474)	$102,829	($78,748)	$1,452,944

34 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
35 RETURN ON AVERAGE INVESTMENT IS CALCULATED FOR JANUARY - JULY USING AN ANNUAL RATE OF 9.0013% (EQUITY 7.0542% , DEBT 1.9471%). RATES ARE BASED ON THE MAY 2015 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 8.9219% (EQUITY 7.0273% , DEBT 1.8946%). RATES ARE BASED ON THE MAY 2016 SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
37 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 38.575%
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 2016 to June 2016

	(1) Jurisdictional Rate Base Actual May 2015 Capital Structure ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,500,445	35.24%	5.33%	1.8783%
Short Term Debt	25,918	0.61%	0.71%	0.0043%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	108,557	2.55%	2.27%	0.0579%
Common Equity	1,791,818	42.09%	10.25%	4.3142%
Deferred ITC - Weighted Cost	7,573	0.18%	7.96%	0.0143%
Accumulated Deferred Income Taxes & Zero Cost ITCs	823,006	19.33%	0.00%	0.0000%
Total	$ 4,257,317	100.00%		6.27%

ITC split between Debt and Equity:

Long Term Debt	$ 1,500,445	Long Term Debt	45.22%
Short Term Debt	25,918	Short Term Debt	0.78%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	1,791,818	Equity - Common	54.00%
Total	$ 3,318,181	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = .0161% * 46.00%	0.0066%
Equity = .0161% * 54.00%	0.0077%
Weighted Cost	0.0143%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.3142%
Deferred ITC - Weighted Cost	0.0077%
	4.3219%
Times Tax Multiplier	1.632200
Total Equity Component	7.0542%

Total Debt Cost Rate:

Long Term Debt	1.8783%
Short Term Debt	0.0043%
Customer Deposits	0.0579%
Deferred ITC - Weighted Cost	0.0066%
Total Debt Component	1.9471%
	9.0013%

Notes:

Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (4) - Column (2) x Column (3)

Tampa Electric Company
Calculation of Revenue Requirement Rate of Return
For Cost Recovery Clauses
July 2016 to December 2016

	(1) Jurisdictional Rate Base Actual May 2016 Capital Structure ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,548,383	35.17%	5.17%	1.82%
Short Term Debt	25,435	0.58%	0.90%	0.01%
Preferred Stock	0	0.00%	0.00%	0.00%
Customer Deposits	106,847	2.43%	2.29%	0.06%
Common Equity	1,847,526	41.96%	10.25%	4.30%
Deferred ITC - Weighted Cost	7,686	0.17%	7.89%	0.01%
Accumulated Deferred Income Taxes & Zero Cost ITCs	866,653	19.69%	0.00%	0.00%
Total	$ 4,402,530	100.00%		6.20%

ITC split between Debt and Equity:

Long Term Debt	$ 1,548,383	Long Term Debt	45.26%
Short Term Debt	25,435	Short Term Debt	0.74%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	1,847,526	Equity - Common	54.00%
Total	$ 3,421,345	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = .0100% * 46.00%	0.0046%
Equity = .0100% * 54.00%	0.0054%
Weighted Cost	0.0100%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.3000%
Deferred ITC - Weighted Cost	0.0054%
	4.3054%
Times Tax Multiplier	1.632200
Total Equity Component	7.0273%

Total Debt Cost Rate:

Long Term Debt	1.8200%
Short Term Debt	0.0100%
Customer Deposits	0.0600%
Deferred ITC - Weighted Cost	0.0046%
Total Debt Component	1.8946%
	8.9219%

Notes:

Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (4) - Column (2) x Column (3)

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 1

PROJECTED CAPACITY COST RECOVERY

JANUARY 2017 - DECEMBER 2017

AND

SCHEDULE E12

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 51
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 2017 THROUGH DECEMBER 2017
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	53.13%	8,934,018	1,919	1.07835	1.05122	9,391,609	2,070	46.88%	56.83%	56.06%
GS, TS	62.24%	1,001,850	184	1.07835	1.05120	1,053,149	198	5.26%	5.44%	5.43%
GSD Optional	3.82%	400,105	59	1.07384	1.04767	419,179	64	2.09%	1.76%	1.79%
GSD, SBF	73.08%	7,655,374	1,136	1.07384	1.04767	8,020,323	1,220	40.03%	33.50%	34.00%
IS,SBI	128.17%	908,781	81	1.02975	1.01779	924,945	83	4.62%	2.28%	2.46%
LS1	354.65%	213,951	7	1.07835	1.05122	224,909	7	1.12%	0.19%	0.26%
TOTAL		19,114,079	3,387			20,034,114	3,642	100.00%	100.00%	100.00%

(1) AVG 12 CP load factor based on 2016 projected calendar data.
(2) Projected MWH sales for the period January 2017 thru December 2017.
(3) Based on 12 months average CP at meter.
(4) Based on 2016 projected demand losses.
(5) Based on 2016 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 2017 THROUGH DECEMBER 2017
PROJECTED

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	UNIT POWER CAPACITY CHARGES	1,849,010	1,849,010	824,010	824,010	824,010	824,010	824,010	824,010	824,010	824,010	824,010	824,010	11,938,120
2	CAPACITY PAYMENTS TO COGENERATORS	0	0	0	0	0	0	0	0	0	0	0	0	0
3	(UNIT POWER CAPACITY REVENUES)	(70,289)	(70,289)	(70,289)	(70,289)	(70,289)	(70,289)	(70,289)	(70,289)	(70,289)	(70,289)	(70,289)	(70,290)	(843,469)
4	TOTAL CAPACITY DOLLARS	$1,778,721	$1,778,721	$753,721	$753,721	$753,721	$753,721	$753,721	$753,721	$753,721	$753,721	$753,721	$753,720	$11,094,651
5	SEPARATION FACTOR	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	0.9958992	
6	JURISDICTIONAL CAPACITY DOLLARS	$1,771,427	$1,771,427	$750,630	$750,630	$750,630	$750,630	$750,630	$750,630	$750,630	$750,630	$750,630	$750,629	$11,049,153
7	ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2016 - DEC. 2016													2,986,060
8	TOTAL													$14,035,213
9	REVENUE TAX FACTOR													1.00072
10	TOTAL RECOVERABLE CAPACITY DOLLARS													$14,045,318

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION BY RATE CLASS
JANUARY 2017 THROUGH DECEMBER 2017
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	46.88%	56.83%	506,344	7,368,142	7,874,486	8,934,018	8,934,018				0.00088
GS, CS	5.26%	5.44%	56,812	705,309	762,121	1,001,850	1,001,850				0.00076
GSD, SBF											
Secondary						6,308,487	6,308,487			0.27	
Primary						1,332,269	1,318,946			0.27	
Transmission						14,618	14,326			0.26	
GSD, SBF - Standard	40.03%	33.50%	432,358	4,343,353	4,775,711	7,655,374	7,641,759	58.82%	17,796,925		
GSD - Optional	2.09%	1.76%	22,574	228,188	250,762						
Secondary						388,922	388,922				0.00063
Primary						11,183	11,071				0.00062
IS, SBI											
Primary						231,174	228,862			0.14	
Transmission						677,607	664,055			0.14	
Total IS, SBI	4.62%	2.28%	49,900	295,607	345,507	908,781	892,917	48.65%	2,514,473		
LS1	1.12%	0.19%	12,097	24,634	36,731	213,951	213,951				0.00017
TOTAL	100.00%	100.00%	1,080,085	12,965,233	14,045,318	19,114,079	19,084,488				0.00074

(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 2017 through December 2017.
(7) Projected kWh sales at secondary for the period January 2017 through December 2017.
(8) Col 7 / (Col 9 * 730)*1000
(9) Projected kw demand for the period January 2017 through December 2017.
(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 2017 THROUGH DECEMBER 2017

SCHEDULE E12

CONTRACT	TERM START	TERM END	CONTRACT TYPE
DUKE ENERGY FLORIDA	2/1/2016	2/28/2017	LT
PASCO COGEN	1/1/2009	12/31/2018	LT
SEMINOLE ELECTRIC **	6/1/1992	--------	

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
DUKE ENERGY FLORIDA	250.0	250.0	-	-	-	-	-	-	-	-	-	-
PASCO COGEN	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	1.4	1.4	1.5	1.8	1.3	1.4	1.5	1.7	1.4	1.4	1.2	1.2

CAPACITY	JANUARY ($)	FEBRUARY ($)	MARCH ($)	APRIL ($)	MAY ($)	JUNE ($)	JULY ($)	AUGUST ($)	SEPTEMBER ($)	OCTOBER ($)	NOVEMBER ($)	DECEMBER ($)	TOTAL ($)
DUKE ENERGY FLORIDA	[redacted]												
PASCO COGEN - D													
SUBTOTAL CAPACITY PURCHASES													
SEMINOLE ELECTRIC - D													
VARIOUS MARKET BASED													
SUBTOTAL CAPACITY SALES													
TOTAL PURCHASES AND (SALES)	1,778,721	1,778,721	753,721	753,721	753,721	753,721	753,721	753,721	753,721	753,721	753,721	753,720	11,094,651
TOTAL CAPACITY	**$1,778,721**	**$1,778,721**	**$753,721**	**$753,721**	**$753,721**	**$753,721**	**$753,721**	**$753,721**	**$753,721**	**$753,721**	**$753,721**	**$753,720**	**$11,094,651**

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 2

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2017 - DECEMBER 2017

SCHEDULES E1 THROUGH E10
SCHEDULE H1

TAMPA ELECTRIC COMPANY

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2	Schedule E1 Cost Recovery Clause Calculation	(JAN. 2017 - DEC. 2017)
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. 2014-2017)

TAMPA ELECTRIC COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

SCHEDULE E1

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	663,929,452	19,662,330	3.37666
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	5,260,518	19,662,330 (1)	0.02675
4b.	Polk 1 Ignition Conversion	3,518,938	19,662,330 (1)	0.01790
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4b)**	**672,708,908**	**19,662,330**	**3.42131**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	1,172,410	25,290	4.63586
7.	Energy Cost of Economy Purchases (E9)	10,162,220	306,900	3.31125
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	2,449,180	90,110	2.71799
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**13,783,810**	**422,300**	**3.26399**
11.	**TOTAL AVAILABLE KWH (LINE 5 + LINE 10)**		20,084,630	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	282,200	10,340	2.72921
13.	Fuel Cost of Market Based Sales - Jurisd. (E6)	368,909	11,980	3.07937
14.	Gains on Sales	47,795	NA	NA
15.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**698,904**	**22,320**	**3.13129**
16.	Net Inadvertant Interchange		0	
17.	Wheeling Received Less Wheeling Delivered		0	
18.	Interchange and Wheeling Losses		(175)	
19.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)**	**685,793,814**	**20,062,485**	**3.41829**
20.	Net Unbilled	NA (1)(a)	NA (a)	NA
21.	Company Use	1,169,055 (1)	34,200	0.00611
22.	T & D Losses	30,759,343 (1)	899,846	0.16080
23.	System MWH Sales	685,793,814	19,128,439	3.58521
24.	Wholesale MWH Sales	(451,166)	(14,360)	3.14182
25.	Jurisdictional MWH Sales	685,342,648	19,114,079	3.58554
26.	Jurisdictional Loss Multiplier			1.00002
27.	Jurisdictional MWH Sales Adjusted for Line Loss	685,355,389	19,114,079	3.58561
28.	True-up (2)	(122,639,796)	19,114,079	(0.64162)
29.	Total Jurisdictional Fuel Cost (Excl. GPIF)	562,715,593	19,114,079	2.94398
30.	Revenue Tax Factor			1.00072
31.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	563,120,748	19,114,079	2.94610
32.	GPIF Adjusted for Taxes (2)	969,593	19,114,079	0.00507
33.	**Fuel Factor Adjusted for Taxes Including GPIF**	564,090,341	19,114,079	2.95117
34.	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**2.951**

(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 2017 THROUGH DECEMBER 2017

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2016 - December 2016 (6 months actual, 6 months estimated)	$104,581,497
2.	FINAL TRUE-UP (January 2015 - December 2015) (Per True-Up filed March 2, 2016)	18,058,299
3.	TOTAL OVER/(UNDER) RECOVERY (Line 1 + Line 2) To be included in the 12-month projected period January 2017 through December 2017 (Schedule E1, line 28)	$122,639,796
4.	JURISDICTIONAL MWH SALES (Projected January 2017 through December 2017)	19,114,079
5.	TRUE-UP FACTOR - cents/kWh (Line 3 / Line 4 * 100 cents / 1,000 kWh)	**(0.6416)**

TAMPA ELECTRIC COMPANY
INCENTIVE FACTOR AND TRUE-UP FACTOR
FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

SCHEDULE E1-C

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD / (PENALTY) (January 2017 through December 2017)	$969,593	
	B. TRUE-UP OVER / (UNDER) RECOVERED (January 2016 through December 2016)	$122,639,796	
2.	TOTAL SALES (January 2017 through December 2017)	19,114,079	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR	**0.0051**	Cents/kWh
	B. TRUE-UP FACTOR	**(0.6416)**	Cents/kWh

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

SCHEDULE E1-D

		NET ENERGY FOR LOAD (%)	FUEL COST (%)
ON PEAK		30.12	$24.19
OFF PEAK		69.88	$21.89
		100.00	1.1051

			TOTAL	ON PEAK	OFF PEAK
1	Total Fuel & Net Power Trans (Jurisd)	(Sch E1 line 25)	$685,342,648		
2	MWH Sales (Jurisd)	(Sch E1 line 25)	19,114,079		
2a	Effective MWH Sales (Jurisd)		19,084,489		
3	Cost Per KWH Sold	(line 1 / line 2)	3.5855		
4	Jurisdictional Loss Factor		1.00002		
5	Jurisdictional Fuel Factor		na		
6	True-Up	(Sch E1 line 28)	($122,639,796)		
7	TOTAL	(line 1 x line 4)+line 6	$562,716,559		
8	Revenue Tax Factor		1.00072		
9	Recovery Factor	(line 7 x line 8) / line 2a / 10	2.9507		
10	GPIF Factor	(Sch E1-C line 3a)	0.0051		
11	Recovery Factor Including GPIF	(line 9 + line 10)	2.9558	3.1661	2.8651
12	Recovery Factor Rounded to the Nearest .001 cents/KWH		2.956	3.166	2.865

13	Hours: ON PEAK	25.13%
14	OFF PEAK	74.87%
		100.00%

Jurisdictional Sales (MWH)

Metering Voltage:	Meter	Secondary
Distribution Secondary	16,847,228	16,847,228
Distribution Primary	1,574,626	1,558,880
Transmission	692,225	678,381
Total	19,114,079	19,084,489

	Standard	On-Peak	Off-Peak
Distribution Secondary	2.956	3.166	2.865
Distribution Primary	2.926	3.134	2.836
Transmission	2.897	3.103	2.808
RS 1st Tier	2.642		
RS 2nd Tier	3.642		
Lighting	2.916		

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SCHEDULE E1-E

TAMPA ELECTRIC COMPANY
FUEL COST RECOVERY FACTORS
ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

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)		2.642	3.642
Distribution Secondary	2.956		
Distribution Primary	2.926		
Transmission	2.897		
Lighting Service (1)	2.916		
TIME-OF-USE			
Distribution Secondary - On-Peak	3.166		
Distribution Secondary - Off-Peak	2.865		
Distribution Primary - On-Peak	3.134		
Distribution Primary - Off-Peak	2.836		
Transmission - On-Peak	3.103		
Transmission - Off-Peak	2.808		

(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 2017 THROUGH DECEMBER 2017

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
						ESTIMATED							TOTAL
	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	PERIOD
1. Fuel Cost of System Net Generation	48,849,391	42,680,487	48,972,968	51,732,678	56,829,514	62,138,147	66,243,138	68,018,219	63,299,051	57,991,087	46,643,947	50,530,825	663,929,452
2. Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Fuel Cost of Power Sold [1]	50,730	49,144	54,115	73,943	49,987	68,157	53,801	72,294	58,033	81,900	44,909	41,891	698,904
4. Fuel Cost of Purchased Power	0	0	36,970	94,160	41,730	201,690	67,350	99,330	170,240	398,720	54,170	8,050	1,172,410
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	265,740	220,310	180,240	151,140	195,940	176,490	210,770	249,340	171,790	229,930	217,840	179,650	2,449,180
7. Energy Cost of Economy Purchases	746,840	829,340	749,990	862,750	715,430	1,128,900	731,910	884,800	790,190	1,201,060	824,330	696,680	10,162,220
8. Big Bend Units 1-4 Igniters Conversion Project	452,629	450,036	447,445	444,855	442,263	439,673	437,080	434,490	431,900	429,308	426,716	424,123	5,260,518
9. Polk 1 Ignition Conversion	304,255	302,253	300,250	298,249	296,247	294,245	292,243	290,242	288,240	286,238	284,238	282,238	3,518,938
10. TOTAL FUEL & NET POWER TRANSACTIONS	**50,568,125**	**44,433,282**	**50,633,748**	**53,509,889**	**58,471,137**	**64,310,988**	**67,928,690**	**69,904,127**	**65,093,378**	**60,454,443**	**48,406,332**	**52,079,675**	**685,793,814**
11. Jurisdictional MWH Sold	1,464,122	1,325,639	1,333,499	1,413,388	1,552,878	1,812,746	1,879,801	1,871,923	1,923,717	1,705,307	1,437,178	1,393,881	19,114,079
12. Jurisdictional % of Total Sales	0.9998103	0.9999385	0.9999800	0.9998259	0.9993573	0.9985997	0.9984870	0.9984497	0.9989864	0.9996746	1.0000000	0.9999217	
13. Jurisdictional Total Fuel & Net Power Transactions (Line 10 * Line 12)	50,558,532	44,430,549	50,632,735	53,500,573	58,433,558	64,220,933	67,825,914	69,795,755	65,027,399	60,434,771	48,406,332	52,075,597	685,342,648
14. Jurisdictional Loss Multiplier	1.00002	1.00002	1.00002	1.00002	1.00002	1.00002	1.00002	1.00002	1.00002	1.00002	1.00000	1.00002	
15. JURISD. TOTAL FUEL & NET PWR. TRANS. Adjusted for Line Losses (Line 13 * Line 14)	**50,559,543**	**44,431,438**	**50,633,748**	**53,501,643**	**58,434,727**	**64,222,217**	**67,827,271**	**69,797,151**	**65,028,700**	**60,435,980**	**48,406,332**	**52,076,639**	**685,355,389**
16. Cost Per kWh Sold (Cents/kWh)	3.4532	3.3517	3.7971	3.7853	3.7630	3.5428	3.6082	3.7286	3.3804	3.5440	3.3682	3.7361	3.5856
17. True-up (Cents/kWh) [2]	(0.6416)	(0.6416)	(0.6416)	(0.6416)	(0.6416)	(0.6416)	(0.6416)	(0.6416)	(0.6416)	(0.6416)	(0.6416)	(0.6416)	(0.6416)
18. Total (Cents/kWh) (Line 16+17)	2.8116	2.7101	3.1555	3.1437	3.1214	2.9012	2.9666	3.0870	2.7388	2.9024	2.7266	3.0945	2.9440
19. 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
20. Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	2.8136	2.7121	3.1578	3.1460	3.1236	2.9033	2.9687	3.0892	2.7408	2.9045	2.7286	3.0967	2.9461
21. GPIF Adjusted for Taxes (Cents/kWh) [2]	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051	0.0051
22. TOTAL RECOVERY FACTOR (LINE 20+21)	**2.8187**	**2.7172**	**3.1629**	**3.1511**	**3.1287**	**2.9084**	**2.9738**	**3.0943**	**2.7459**	**2.9096**	**2.7337**	**3.1018**	**2.9512**
23. RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH	**2.819**	**2.717**	**3.163**	**3.151**	**3.129**	**2.908**	**2.974**	**3.094**	**2.746**	**2.910**	**2.734**	**3.102**	**2.951**

[1] Includes Gains
[2] Based on Jurisdictional Sales Only

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TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH JUNE 2017

SCHEDULE E3

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	0	0	0	0	0	0
2. LIGHT OIL	51,955	54,211	49,104	63,536	48,699	63,017
3. COAL	23,952,767	18,327,084	24,107,497	26,987,734	20,887,421	23,132,938
4. NATURAL GAS	24,844,669	24,299,192	24,816,367	24,681,408	35,893,394	38,942,192
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**48,849,391**	**42,680,487**	**48,972,968**	**51,732,678**	**56,829,514**	**62,138,147**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	0	0	0	0	0	0
9. LIGHT OIL	220	240	220	280	220	280
10. COAL	781,920	600,450	729,010	835,720	662,230	713,570
11. NATURAL GAS	666,260	679,870	690,520	676,910	1,092,650	1,192,630
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	450	440	570	600	5,620	4,940
14. TOTAL (MWH)	**1,448,850**	**1,281,000**	**1,420,320**	**1,513,510**	**1,760,720**	**1,911,420**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	0	0	0	0	0	0
16. LIGHT OIL (BBL)	420	440	400	520	400	520
17. COAL (TON)	338,050	257,240	319,890	363,620	285,430	308,670
18. NATURAL GAS (MCF)	4,707,170	4,785,900	4,837,590	4,729,890	7,663,370	8,395,400
19. NUCLEAR (MMBTU)	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	2,440	2,600	2,380	3,040	2,360	3,040
23. COAL	8,073,800	6,172,520	7,537,770	8,674,880	6,864,980	7,410,050
24. NATURAL GAS	4,818,400	4,895,090	4,942,920	4,841,780	7,865,540	8,604,760
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**12,894,640**	**11,070,210**	**12,483,070**	**13,519,700**	**14,732,880**	**16,017,850**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
29. LIGHT OIL	0.02	0.02	0.02	0.02	0.01	0.01
30. COAL	53.96	46.88	51.32	55.22	37.61	37.34
31. NATURAL GAS	45.99	53.07	48.62	44.72	62.06	62.39
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.03	0.03	0.04	0.04	0.32	0.26
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)	123.70	123.21	122.76	122.18	121.75	121.19
37. COAL ($/TON)	70.86	71.25	75.36	74.22	73.18	74.94
38. NATURAL GAS ($/MCF)	5.28	5.08	5.13	5.22	4.68	4.64
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)						
41. HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00
42. LIGHT OIL	21.29	20.85	20.63	20.90	20.64	20.73
43. COAL	2.97	2.97	3.20	3.11	3.04	3.12
44. NATURAL GAS	5.16	4.96	5.02	5.10	4.56	4.53
45. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**3.79**	**3.86**	**3.92**	**3.83**	**3.86**	**3.88**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	0	0	0	0	0	0
49. LIGHT OIL	11,091	10,833	10,818	10,857	10,727	10,857
50. COAL	10,326	10,280	10,340	10,380	10,366	10,384
51. NATURAL GAS	7,232	7,200	7,158	7,153	7,199	7,215
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**8,900**	**8,642**	**8,789**	**8,933**	**8,368**	**8,380**
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	23.62	22.59	22.32	22.69	22.14	22.51
57. COAL	3.06	3.05	3.31	3.23	3.15	3.24
58. NATURAL GAS	3.73	3.57	3.59	3.65	3.28	3.27
59. NUCLEAR	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)	**3.37**	**3.33**	**3.45**	**3.42**	**3.23**	**3.25**

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD: JULY 2017 THROUGH DECEMBER 2017

SCHEDULE E3

		Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)								
1.	HEAVY OIL	0	0	0	0	0	0	0
2.	LIGHT OIL	48,306	62,518	50,316	62,028	49,928	47,397	651,015
3.	COAL	29,495,002	32,449,216	30,662,100	31,440,579	22,138,218	24,175,762	307,756,318
4.	NATURAL GAS	36,699,830	35,506,485	32,586,635	26,488,480	24,455,801	26,307,666	355,522,119
5.	NUCLEAR	0	0	0	0	0	0	0
6.	OTHER	0	0	0	0	0	0	0
7.	**TOTAL ($)**	**66,243,138**	**68,018,219**	**63,299,051**	**57,991,087**	**46,643,947**	**50,530,825**	**663,929,452**
SYSTEM NET GENERATION (MWH)								
8.	HEAVY OIL	0	0	0	0	0	0	0
9.	LIGHT OIL	220	280	220	280	220	220	2,900
10.	COAL	871,010	955,760	901,400	907,890	634,260	703,830	9,297,050
11.	NATURAL GAS	1,098,360	1,055,040	956,880	740,540	725,740	750,590	10,325,990
12.	NUCLEAR	0	0	0	0	0	0	0
13.	OTHER	4,820	4,650	3,860	3,990	3,400	3,050	36,390
14.	**TOTAL (MWH)**	**1,974,410**	**2,015,730**	**1,862,360**	**1,652,700**	**1,363,620**	**1,457,690**	**19,662,330**
UNITS OF FUEL BURNED								
15.	HEAVY OIL (BBL)	0	0	0	0	0	0	0
16.	LIGHT OIL (BBL)	400	520	420	520	420	400	5,380
17.	COAL (TON)	379,310	416,990	392,020	395,620	275,420	303,260	4,035,520
18.	NATURAL GAS (MCF)	7,743,500	7,445,360	6,753,620	5,205,270	5,045,980	5,277,600	72,590,650
19.	NUCLEAR (MMBTU)	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	2,360	2,960	2,440	2,960	2,420	2,360	31,360
23.	COAL	9,045,190	9,912,000	9,330,250	9,421,020	6,568,470	7,257,090	96,268,020
24.	NATURAL GAS	7,931,180	7,634,540	6,921,750	5,331,290	5,151,100	5,403,940	74,342,290
25.	NUCLEAR	0	0	0	0	0	0	0
26.	OTHER	0	0	0	0	0	0	0
27.	**TOTAL (MMBTU)**	**16,978,730**	**17,549,500**	**16,254,440**	**14,755,270**	**11,721,990**	**12,663,390**	**170,641,670**
GENERATION MIX (% MWH)								
28.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29.	LIGHT OIL	0.01	0.01	0.01	0.02	0.02	0.02	0.01
30.	COAL	44.12	47.42	48.40	54.93	46.51	48.28	47.28
31.	NATURAL GAS	55.63	52.34	51.38	44.81	53.22	51.49	52.52
32.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33.	OTHER	0.24	0.23	0.21	0.24	0.25	0.21	0.19
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)	120.77	120.23	119.80	119.28	118.88	118.49	121.01
37.	COAL ($/TON)	77.76	77.82	78.22	79.47	80.38	79.72	76.26
38.	NATURAL GAS ($/MCF)	4.74	4.77	4.83	5.09	4.85	4.98	4.90
39.	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)								
41.	HEAVY OIL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42.	LIGHT OIL	20.47	21.12	20.62	20.96	20.63	20.08	20.76
43.	COAL	3.26	3.27	3.29	3.34	3.37	3.33	3.20
44.	NATURAL GAS	4.63	4.65	4.71	4.97	4.75	4.87	4.78
45.	NUCLEAR	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)**	**3.90**	**3.88**	**3.89**	**3.93**	**3.98**	**3.99**	**3.89**
BTU BURNED PER KWH (BTU/KWH)								
48.	HEAVY OIL	0	0	0	0	0	0	0
49.	LIGHT OIL	10,727	10,571	11,091	10,571	11,000	10,727	10,814
50.	COAL	10,385	10,371	10,351	10,377	10,356	10,311	10,355
51.	NATURAL GAS	7,221	7,236	7,234	7,199	7,098	7,200	7,200
52.	NUCLEAR	0	0	0	0	0	0	0
53.	OTHER	0	0	0	0	0	0	0
54.	**TOTAL (BTU/KWH)**	**8,599**	**8,706**	**8,728**	**8,928**	**8,596**	**8,687**	**8,679**
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	21.96	22.33	22.87	22.15	22.69	21.54	22.45
57.	COAL	3.39	3.40	3.40	3.46	3.49	3.43	3.31
58.	NATURAL GAS	3.34	3.37	3.41	3.58	3.37	3.50	3.44
59.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61.	**TOTAL (CENTS/KWH)**	**3.36**	**3.37**	**3.40**	**3.51**	**3.42**	**3.47**	**3.38**

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JANUARY 2017

(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	1.6	270	22.7	-	22.7	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	180	16.1	-	16.1	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR [5]	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR [3]	**3.1**	**450**	**19.5**	**-**	**19.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	131,070	-	-	-	10,462	COAL	57,740	23,749,394	1,371,290.0	4,225,626	3.22	73.18
7. TOTAL BIG BEND #1	**395**	**131,070**	**44.6**	**75.4**	**84.9**	**10,462**		**-**	**-**	**1,371,290.0**	**4,225,626**	**3.22**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	179,920	-	-	-	10,271	COAL	79,310	23,301,223	1,848,020.0	5,804,202	3.23	73.18
10. TOTAL BIG BEND #2	**395**	**179,920**	**61.2**	**78.0**	**84.2**	**10,271**		**-**	**-**	**1,848,020.0**	**5,804,202**	**3.23**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	206,650	-	-	-	10,344	COAL	92,940	22,999,032	2,137,530.0	6,801,692	3.29	73.18
13. TOTAL BIG BEND #3	**400**	**206,650**	**69.4**	**86.0**	**81.5**	**10,344**		**-**	**-**	**2,137,530.0**	**6,801,692**	**3.29**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	123,670	-	-	-	10,366	COAL	55,740	22,998,027	1,281,910.0	4,081,918	3.30	73.23
16. TOTAL BIG BEND #4	**442**	**123,670**	**37.6**	**81.9**	**81.1**	**10,366**		**-**	**-**	**1,281,910.0**	**4,081,918**	**3.30**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	17,950	-	18,450.0	95,145	-	5.30
18. BIG BEND 1-4 COAL TOTAL	**1,632**	**641,310**	**52.8**	**80.4**	**82.8**	**10,352**	**COAL**	**285,730**	**23,234,347**	**6,638,750.0**	**20,913,438**	**3.26**	**73.19**
19. B.B.C.T.#4 OIL	61	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	61	50	0.1	-	82.0	12,000	GAS	590	1,016,949	600.0	3,127	6.25	5.30
21. B.B.C.T.#4 TOTAL	**61**	**50**	**0.1**	**98.3**	**82.0**	**12,000**	**-**	**-**	**-**	**600.0**	**3,127**	**6.25**	**-**
22. BIG BEND STATION TOTAL	**1,693**	**641,360**	**50.9**	**81.0**	**82.8**	**10,352**	**-**	**-**	**-**	**6,639,350.0**	**21,011,710**	**3.28**	**-**
23. POLK #1 GASIFIER	220	140,610	85.9	-	97.4	10,206	COAL	52,320	27,428,326	1,435,050.0	2,944,184	2.09	56.27
24. POLK #1 CT GAS [4]	195	0	0.0	-	0.0	0	GAS	2,040	0	0.0	0	0.00	0.00
25. POLK #1 TOTAL	**220**	**140,610**	**85.9**	**79.0**	**97.4**	**10,206**	**-**	**-**	**-**	**1,435,050.0**	**2,944,184**	**2.09**	**-**
26. POLK #2 CC GAS	1,195	389,530	43.8	-	58.9	6,744	GAS	2,555,340	1,028,000	2,626,890.0	13,544,728	3.48	5.30
27. POLK #2 CC OIL	187	220	0.2	-	11.8	11,091	LGT OIL	420	5,809,524	2,440.0	51,955	23.62	123.70
28. POLK #2 CC TOTAL	**1,195**	**389,750**	**43.8**	**96.9**	**58.8**	**6,746**	**-**	**-**	**-**	**2,629,330.0**	**13,596,683**	**3.49**	**-**
29. POLK STATION TOTAL	**1,415**	**530,360**	**50.4**	**94.2**	**65.7**	**7,663**	**-**	**-**	**-**	**4,064,380.0**	**16,540,867**	**3.12**	**-**
30. BAYSIDE #1	792	108,500	18.4	96.9	59.8	7,327	GAS	773,300	1,027,997	794,950.0	4,098,921	3.78	5.30
31. BAYSIDE #2	1,047	168,150	21.6	95.9	22.4	8,299	GAS	1,357,510	1,027,992	1,395,510.0	7,195,561	4.28	5.30
32. BAYSIDE #3	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
33. BAYSIDE #4	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. BAYSIDE #5	61	30	0.1	98.6	49.2	15,000	GAS	440	1,022,727	450.0	2,332	7.77	5.30
35. BAYSIDE #6	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
36. BAYSIDE TOTAL	**2,083**	**276,680**	**17.9**	**88.0**	**29.6**	**7,919**	**GAS**	**2,131,250**	**1,027,993**	**2,190,910.0**	**11,296,814**	**4.08**	**5.30**
37. SYSTEM	**5,194**	**1,448,850**	**37.5**	**87.3**	**57.6**	**8,900**	**-**	**-**	**-**	**12,894,640.0**	**48,849,391**	**3.37**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

[1] As burned fuel cost system total includes ignition.
[3] AC rating
[5] Commercial operation scheduled for May 2017

[2] Fuel burned (MM BTU) system total excludes ignition.
[4] Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: FEBRUARY 2017

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) [2]	AS BURNED FUEL COST ($) [1]	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	260	24.2	-	24.2	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	180	17.9	-	17.9	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR [5]	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR [3]	**3.1**	**440**	**21.1**	**-**	**21.1**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	96,840	-	-	-	10,423	COAL	42,500	23,750,824	1,009,410.0	3,138,477	3.24	73.85
7. TOTAL BIG BEND #1	**395**	**96,840**	**36.5**	**51.8**	**89.8**	**10,423**		**-**	**-**	**1,009,410.0**	**3,138,477**	**3.24**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	111,840	-	-	-	10,185	COAL	48,890	23,299,243	1,139,100.0	3,610,353	3.23	73.85
10. TOTAL BIG BEND #2	**395**	**111,840**	**42.1**	**49.8**	**92.8**	**10,185**		**-**	**-**	**1,139,100.0**	**3,610,353**	**3.23**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	194,400	-	-	-	10,305	COAL	87,100	22,999,541	2,003,260.0	6,432,027	3.31	73.85
13. TOTAL BIG BEND #3	**400**	**194,400**	**72.3**	**86.0**	**84.8**	**10,305**		**-**	**-**	**2,003,260.0**	**6,432,027**	**3.31**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	70,460	-	-	-	10,295	COAL	31,540	22,999,049	725,390.0	2,337,395	3.32	74.11
16. TOTAL BIG BEND #4	**442**	**70,460**	**23.7**	**43.9**	**91.1**	**10,295**		**-**	**-**	**725,390.0**	**2,337,395**	**3.32**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	22,120	-	22,740.0	112,878	-	5.10
18. BIG BEND 1-4 COAL TOTAL	**1,632**	**473,540**	**43.2**	**57.5**	**88.5**	**10,299**	**COAL**	**210,030**	**23,221,254**	**4,877,160.0**	**15,518,252**	**3.28**	**73.89**
19. B.B.C.T.#4 OIL	61	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	61	20	0.0	-	32.8	14,500	GAS	280	1,035,714	290.0	1,429	7.15	5.10
21. B.B.C.T.#4 TOTAL	**61**	**20**	**0.0**	**98.3**	**32.8**	**14,500**	**-**	**-**	**-**	**290.0**	**1,429**	**7.15**	**-**
22. BIG BEND STATION TOTAL	**1,693**	**473,560**	**41.6**	**59.0**	**88.5**	**10,300**	**-**	**-**	**-**	**4,877,450.0**	**15,632,559**	**3.30**	**-**
23. POLK #1 GASIFIER	220	126,910	85.8	-	97.4	10,207	COAL	47,210	27,438,255	1,295,360.0	2,695,954	2.12	57.11
24. POLK #1 CT GAS [4]	195	0	0.0	-	0.0	0	GAS	2,040	0	0.0	0	0.00	0.00
25. POLK #1 TOTAL	**220**	**126,910**	**85.8**	**79.0**	**97.4**	**10,207**	**-**	**-**	**-**	**1,295,360.0**	**2,695,954**	**2.12**	**-**
26. POLK #2 CC GAS	1,195	439,610	54.7	-	55.3	6,742	GAS	2,883,130	1,028,004	2,963,870.0	14,712,632	3.35	5.10
27. POLK #2 CC OIL	187	240	0.2	-	16.0	10,833	LGT OIL	440	5,909,091	2,600.0	54,211	22.59	123.21
28. POLK #2 CC TOTAL	**1,195**	**439,850**	**54.8**	**96.9**	**55.2**	**6,744**	**-**	**-**	**-**	**2,966,470.0**	**14,766,843**	**3.36**	**-**
29. POLK STATION TOTAL	**1,415**	**566,760**	**59.6**	**94.2**	**61.2**	**7,520**	**-**	**-**	**-**	**4,261,830.0**	**17,462,797**	**3.08**	**-**
30. BAYSIDE #1	792	109,340	20.5	39.8	45.9	7,456	GAS	793,060	1,028,005	815,270.0	4,046,991	3.70	5.10
31. BAYSIDE #2	1,047	130,900	18.6	95.9	19.3	8,523	GAS	1,085,270	1,028,002	1,115,660.0	5,538,140	4.23	5.10
32. BAYSIDE #3	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
33. BAYSIDE #4	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. BAYSIDE #5	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
35. BAYSIDE #6	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
36. BAYSIDE TOTAL	**2,083**	**240,240**	**17.2**	**63.4**	**26.2**	**8,038**	**GAS**	**1,878,330**	**1,028,004**	**1,930,930.0**	**9,585,131**	**3.99**	**5.10**
37. SYSTEM	**5,194**	**1,281,000**	**36.7**	**70.3**	**53.8**	**8,642**	**-**	**-**	**-**	**11,070,210.0**	**42,680,487**	**3.33**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

[1] As burned fuel cost system total includes ignition.
[2] Fuel burned (MM BTU) system total excludes ignition.
[3] AC rating
[4] Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.
[5] Commercial operation scheduled for May 2017

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MARCH 2017

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) [2]	AS BURNED FUEL COST ($) [1]	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	330	27.7	-	27.7	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	240	21.5	-	21.5	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR [5]	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR [3]	**3.1**	**570**	**24.7**	**-**	**24.7**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	197,020	-	-	-	10,389	COAL	86,180	23,750,870	2,046,850.0	6,534,318	3.32	75.82
7. TOTAL BIG BEND #1	**395**	**197,020**	**67.0**	**80.6**	**91.7**	**10,389**		**-**	**-**	**2,046,850.0**	**6,534,318**	**3.32**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	197,880	-	-	-	10,260	COAL	87,140	23,299,518	2,030,320.0	6,607,105	3.34	75.82
10. TOTAL BIG BEND #2	**395**	**197,880**	**67.3**	**82.0**	**84.8**	**10,260**		**-**	**-**	**2,030,320.0**	**6,607,105**	**3.34**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	208,280	-	-	-	10,323	COAL	93,480	23,000,107	2,150,050.0	7,087,818	3.40	75.82
13. TOTAL BIG BEND #3	**400**	**208,280**	**70.0**	**86.0**	**83.2**	**10,323**		**-**	**-**	**2,150,050.0**	**7,087,818**	**3.40**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	75,960	-	-	-	10,457	COAL	34,530	23,002,896	794,290.0	2,621,144	3.45	75.91
16. TOTAL BIG BEND #4	**442**	**75,960**	**23.1**	**79.3**	**76.7**	**10,457**		**-**	**-**	**794,290.0**	**2,621,144**	**3.45**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	21,710	-	22,310.0	112,049	-	5.16
18. BIG BEND 1-4 COAL TOTAL	**1,632**	**679,140**	**55.9**	**81.9**	**85.1**	**10,339**	**COAL**	**301,330**	**23,301,729**	**7,021,510.0**	**22,850,385**	**3.36**	**75.83**
19. B.B.C.T.#4 OIL	61	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	61	300	0.7	-	70.3	12,533	GAS	3,660	1,027,322	3,760.0	18,890	6.30	5.16
21. B.B.C.T.#4 TOTAL	**61**	**300**	**0.7**	**98.3**	**70.3**	**12,533**	**-**	**-**	**-**	**3,760.0**	**18,890**	**6.30**	**-**
22. BIG BEND STATION TOTAL	**1,693**	**679,440**	**53.9**	**82.5**	**85.1**	**10,340**	**-**	**-**	**-**	**7,025,270.0**	**22,981,324**	**3.38**	**-**
23. POLK #1 GASIFIER	220	49,870	30.5	-	97.3	10,352	COAL	18,560	27,815,733	516,260.0	1,145,063	2.30	61.70
24. POLK #1 CT GAS [4]	195	3,390	2.3	-	102.3	8,263	GAS	34,830	804,192	28,010.0	140,590	4.15	4.04
25. POLK #1 TOTAL	**220**	**53,260**	**32.5**	**28.0**	**97.6**	**10,219**	**-**	**-**	**-**	**544,270.0**	**1,285,653**	**2.41**	**-**
26. POLK #2 CC GAS	1,195	484,340	54.5	-	54.3	6,765	GAS	3,187,500	1,028,000	3,276,750.0	16,451,206	3.40	5.16
27. POLK #2 CC OIL	187	220	0.2	-	14.7	10,818	LGT OIL	400	5,950,000	2,380.0	49,104	22.32	122.76
28. POLK #2 CC TOTAL	**1,195**	**484,560**	**54.5**	**96.9**	**54.2**	**6,767**	**-**	**-**	**-**	**3,279,130.0**	**16,500,310**	**3.41**	**-**
29. POLK STATION TOTAL	**1,415**	**537,820**	**51.1**	**86.2**	**56.7**	**7,109**	**-**	**-**	**-**	**3,823,400.0**	**17,785,963**	**3.31**	**-**
30. BAYSIDE #1	792	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
31. BAYSIDE #2	1,047	202,390	26.0	95.9	26.9	8,069	GAS	1,588,680	1,027,998	1,633,160.0	8,199,436	4.05	5.16
32. BAYSIDE #3	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
33. BAYSIDE #4	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. BAYSIDE #5	61	100	0.2	85.9	82.0	12,400	GAS	1,210	1,024,793	1,240.0	6,245	6.25	5.16
35. BAYSIDE #6	61	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
36. BAYSIDE TOTAL	**2,083**	**202,490**	**13.1**	**50.7**	**26.9**	**8,072**	**GAS**	**1,589,890**	**1,027,996**	**1,634,400.0**	**8,205,681**	**4.05**	**5.16**
37. SYSTEM	**5,194**	**1,420,320**	**36.8**	**70.7**	**56.8**	**8,789**	**-**	**-**	**-**	**12,483,070.0**	**48,972,968**	**3.45**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

[1] As burned fuel cost system total includes ignition.
[2] Fuel burned (MM BTU) system total excludes ignition.
[3] AC rating
[4] Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.
[5] Commercial operation scheduled for May 2017

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: APRIL 2017

(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	1.6	320	27.8	-	27.8	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	280	25.9	-	25.9	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR [5]	-	-	-	-	-	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR [3]	**3.1**	**600**	**26.9**	**-**	**26.9**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	191,130	-	-	-	10,536	COAL	84,790	23,748,791	2,013,660.0	6,481,070	3.39	76.44
7. TOTAL BIG BEND #1	**385**	**191,130**	**69.0**	**80.6**	**89.1**	**10,536**		**-**	**-**	**2,013,660.0**	**6,481,070**	**3.39**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	180,720	-	-	-	10,288	COAL	79,790	23,301,166	1,859,200.0	6,098,887	3.37	76.44
10. TOTAL BIG BEND #2	**385**	**180,720**	**65.2**	**82.0**	**86.8**	**10,288**		**-**	**-**	**1,859,200.0**	**6,098,887**	**3.37**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	162,850	-	-	-	10,383	COAL	73,520	22,998,504	1,690,850.0	5,619,626	3.45	76.44
13. TOTAL BIG BEND #3	**395**	**162,850**	**57.3**	**77.4**	**82.5**	**10,383**		**-**	**-**	**1,690,850.0**	**5,619,626**	**3.45**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	165,050	-	-	-	10,443	COAL	74,940	23,000,267	1,723,640.0	5,730,438	3.47	76.47
16. TOTAL BIG BEND #4	**437**	**165,050**	**52.5**	**81.9**	**81.0**	**10,443**		**-**	**-**	**1,723,640.0**	**5,730,438**	**3.47**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	17,950	-	18,450.0	94,064	-	5.24
18. BIG BEND 1-4 COAL TOTAL	**1,602**	**699,750**	**60.7**	**80.5**	**84.9**	**10,414**	**COAL**	**313,040**	**23,279,293**	**7,287,350.0**	**23,930,021**	**3.42**	**76.44**
19. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	56	1,040	2.6	-	97.7	11,808	GAS	11,940	1,028,476	12,280.0	62,569	6.02	5.24
21. B.B.C.T.#4 TOTAL	**56**	**1,040**	**2.6**	**81.9**	**97.7**	**11,808**	**-**	**-**	**-**	**12,280.0**	**62,569**	**6.02**	**-**
22. BIG BEND STATION TOTAL	**1,658**	**700,790**	**58.7**	**80.5**	**85.0**	**10,416**	**-**	**-**	**-**	**7,299,630.0**	**24,086,654**	**3.44**	**-**
23. POLK #1 GASIFIER	220	135,970	85.8	-	97.5	10,205	COAL	50,580	27,432,384	1,387,530.0	2,963,649	2.18	58.59
24. POLK #1 CT GAS [4]	195	3,500	2.5	-	94.5	8,469	GAS	30,870	960,155	29,640.0	151,079	4.32	4.89
25. POLK #1 TOTAL	**220**	**139,470**	**88.0**	**79.0**	**97.4**	**10,161**	**-**	**-**	**-**	**1,417,170.0**	**3,114,728**	**2.23**	**-**
26. POLK #2 CC GAS	1,063	456,540	59.7	-	57.4	6,757	GAS	3,000,970	1,027,998	3,084,990.0	15,726,059	3.44	5.24
27. POLK #2 CC OIL	159	280	0.2	-	17.6	10,857	LGT OIL	520	5,846,154	3,040.0	63,536	22.69	122.18
28. POLK #2 CC TOTAL	**1,063**	**456,820**	**59.7**	**96.9**	**57.3**	**6,760**	**-**	**-**	**-**	**3,088,030.0**	**15,789,595**	**3.46**	**-**
29. POLK STATION TOTAL	**1,283**	**596,290**	**64.6**	**93.9**	**63.4**	**7,555**	**-**	**-**	**-**	**4,505,200.0**	**18,904,323**	**3.17**	**-**
30. BAYSIDE #1	701	121,550	24.1	59.7	46.4	7,649	GAS	904,460	1,027,995	929,780.0	4,739,665	3.90	5.24
31. BAYSIDE #2	929	92,160	13.8	48.0	28.5	8,242	GAS	738,900	1,027,988	759,580.0	3,872,076	4.20	5.24
32. BAYSIDE #3	56	530	1.3	98.6	94.6	11,830	GAS	6,100	1,027,869	6,270.0	31,966	6.03	5.24
33. BAYSIDE #4	56	420	1.0	98.6	93.8	12,024	GAS	4,910	1,028,513	5,050.0	25,730	6.13	5.24
34. BAYSIDE #5	56	660	1.6	95.3	90.7	12,106	GAS	7,770	1,028,314	7,990.0	40,717	6.17	5.24
35. BAYSIDE #6	56	510	1.3	82.2	91.1	12,157	GAS	6,020	1,029,900	6,200.0	31,547	6.19	5.24
36. BAYSIDE TOTAL	**1,854**	**215,830**	**16.2**	**57.9**	**36.7**	**7,945**	**GAS**	**1,668,160**	**1,028,001**	**1,714,870.0**	**8,741,701**	**4.05**	**5.24**
37. SYSTEM	**4,798**	**1,513,510**	**43.8**	**75.3**	**64.3**	**8,933**	**-**	**-**	**-**	**13,519,700.0**	**51,732,678**	**3.42**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

[1] As burned fuel cost system total includes ignition.
[3] AC rating
[5] Commercial operation scheduled for May 2017

[2] Fuel burned (MM BTU) system total excludes ignition.
[4] Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: MAY 2017

(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	1.6	340	28.6	-	28.6	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	290	26.0	-	26.0	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	18.0	4,990	37.3	-	37.3	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR [3]	**21.1**	**5,620**	**35.8**	**-**	**35.8**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	141,070	-	-	-	10,560	COAL	62,730	23,748,605	1,489,750.0	4,771,479	3.38	76.06
7. TOTAL BIG BEND #1	**385**	**141,070**	**49.2**	**80.6**	**86.8**	**10,560**		**-**	**-**	**1,489,750.0**	**4,771,479**	**3.38**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	162,250	-	-	-	10,285	COAL	71,620	23,300,614	1,668,790.0	5,447,687	3.36	76.06
10. TOTAL BIG BEND #2	**385**	**162,250**	**56.6**	**82.0**	**86.9**	**10,285**		**-**	**-**	**1,668,790.0**	**5,447,687**	**3.36**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	0	-	-	-	0	COAL	0	0	0.0	0	0.00	0.00
13. TOTAL BIG BEND #3	**395**	**0**	**0.0**	**0.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	218,300	-	-	-	10,405	COAL	98,760	22,999,190	2,271,400.0	7,513,907	3.44	76.08
16. TOTAL BIG BEND #4	**437**	**218,300**	**67.1**	**81.9**	**82.7**	**10,405**		**-**	**-**	**2,271,400.0**	**7,513,907**	**3.44**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	10,020	-	10,300.0	47,006	-	4.69
18. BIG BEND 1-4 COAL TOTAL	**1,602**	**521,620**	**43.8**	**61.4**	**85.1**	**10,410**	**COAL**	**233,110**	**23,293,467**	**5,429,940.0**	**17,733,073**	**3.40**	**76.07**
19. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	56	220	0.5	-	98.2	11,955	GAS	2,560	1,027,344	2,630.0	12,009	5.46	4.69
21. B.B.C.T.#4 TOTAL	**56**	**220**	**0.5**	**98.3**	**98.2**	**11,955**	**-**	**-**	**-**	**2,630.0**	**12,009**	**5.46**	**-**
22. BIG BEND STATION TOTAL	**1,658**	**521,840**	**42.3**	**62.7**	**85.1**	**10,410**	**-**	**-**	**-**	**5,432,570.0**	**17,792,088**	**3.41**	**-**
23. POLK #1 GASIFIER	220	140,610	85.9	-	97.4	10,206	COAL	52,320	27,428,135	1,435,040.0	3,107,342	2.21	59.39
24. POLK #1 CT GAS [4]	195	0	0.0	-	0.0	0	GAS	2,040	0	0.0	0	0.00	0.00
25. POLK #1 TOTAL	**220**	**140,610**	**85.9**	**79.0**	**97.4**	**10,206**	**-**	**-**	**-**	**1,435,040.0**	**3,107,342**	**2.21**	**-**
26. POLK #2 CC GAS	1,063	555,280	70.2	-	70.1	6,749	GAS	3,645,270	1,028,001	3,747,340.0	17,100,485	3.08	4.69
27. POLK #2 CC OIL	159	220	0.2	-	17.3	10,727	LGT OIL	400	5,900,000	2,360.0	48,699	22.14	121.75
28. POLK #2 CC TOTAL	**1,063**	**555,500**	**70.2**	**96.9**	**70.0**	**6,750**	**-**	**-**	**-**	**3,749,700.0**	**17,149,184**	**3.09**	**-**
29. POLK STATION TOTAL	**1,283**	**696,110**	**72.9**	**93.9**	**74.2**	**7,448**	**-**	**-**	**-**	**5,184,740.0**	**20,256,526**	**2.91**	**-**
30. BAYSIDE #1	701	266,210	51.0	96.9	58.8	7,482	GAS	1,937,520	1,028,000	1,991,770.0	9,089,185	3.41	4.69
31. BAYSIDE #2	929	270,540	39.1	95.9	40.6	7,832	GAS	2,061,130	1,027,999	2,118,840.0	9,669,056	3.57	4.69
32. BAYSIDE #3	56	100	0.2	98.6	89.3	13,200	GAS	1,280	1,031,250	1,320.0	6,005	6.01	4.69
33. BAYSIDE #4	56	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. BAYSIDE #5	56	150	0.4	98.6	89.3	12,333	GAS	1,800	1,027,778	1,850.0	8,444	5.63	4.69
35. BAYSIDE #6	56	150	0.4	98.6	89.3	11,933	GAS	1,750	1,022,857	1,790.0	8,210	5.47	4.69
36. BAYSIDE TOTAL	**1,854**	**537,150**	**38.9**	**93.6**	**47.9**	**7,662**	**GAS**	**4,003,480**	**1,027,998**	**4,115,570.0**	**18,780,900**	**3.50**	**4.69**
37. SYSTEM	**4,816**	**1,760,720**	**49.1**	**82.6**	**65.9**	**8,368**	**-**	**-**	**-**	**14,732,880.0**	**56,829,514**	**3.23**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

[1] As burned fuel cost system total includes ignition.
[2] Fuel burned (MM BTU) system total excludes ignition.
[3] AC rating
[4] Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JUNE 2017

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) [2]	AS BURNED FUEL COST ($) [1]	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	290	25.2	-	25.2	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	270	25.0	-	25.0	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	18.0	4,380	33.8	-	33.8	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR [3]	**21.1**	**4,940**	**32.5**	**-**	**32.5**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	185,940	-	-	-	10,577	COAL	82,810	23,749,185	1,966,670.0	6,406,432	3.45	77.36
7. TOTAL BIG BEND #1	**385**	**185,940**	**67.1**	**80.6**	**86.2**	**10,577**		**-**	**-**	**1,966,670.0**	**6,406,432**	**3.45**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	184,740	-	-	-	10,288	COAL	81,570	23,300,233	1,900,600.0	6,310,502	3.42	77.36
10. TOTAL BIG BEND #2	**385**	**184,740**	**66.6**	**82.0**	**86.8**	**10,288**		**-**	**-**	**1,900,600.0**	**6,310,502**	**3.42**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	0	-	-	-	0	COAL	0	0	0.0	0	0.00	0.00
13. TOTAL BIG BEND #3	**395**	**0**	**0.0**	**0.0**	**0.0**	**0**		**-**	**-**	**0.0**	**0**	**0.00**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	206,920	-	-	-	10,416	COAL	93,710	22,999,146	2,155,250.0	7,256,800	3.51	77.44
16. TOTAL BIG BEND #4	**437**	**206,920**	**65.8**	**81.9**	**82.2**	**10,416**		**-**	**-**	**2,155,250.0**	**7,256,800**	**3.51**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	22,960	-	23,600.0	106,819	-	4.65
18. BIG BEND 1-4 COAL TOTAL	**1,602**	**577,600**	**50.1**	**61.4**	**84.9**	**10,427**	**COAL**	**258,090**	**23,334,961**	**6,022,520.0**	**19,973,734**	**3.46**	**77.39**
19. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	56	1,870	4.6	-	98.2	11,781	GAS	21,430	1,027,998	22,030.0	99,700	5.33	4.65
21. B.B.C.T.#4 TOTAL	**56**	**1,870**	**4.6**	**98.3**	**98.2**	**11,781**	**-**	**-**	**-**	**22,030.0**	**99,700**	**5.33**	**-**
22. BIG BEND STATION TOTAL	**1,658**	**579,470**	**48.5**	**62.7**	**85.0**	**10,431**	**-**	**-**	**-**	**6,044,550.0**	**20,180,253**	**3.48**	**-**
23. POLK #1 GASIFIER	220	135,970	85.8	-	97.5	10,205	COAL	50,580	27,432,384	1,387,530.0	3,052,385	2.24	60.35
24. POLK #1 CT GAS [4]	195	3,500	2.5	-	94.5	8,460	GAS	30,840	960,117	29,610.0	133,988	3.83	4.34
25. POLK #1 TOTAL	**220**	**139,470**	**88.0**	**79.0**	**97.4**	**10,161**	**-**	**-**	**-**	**1,417,140.0**	**3,186,373**	**2.28**	**-**
26. POLK #2 CC GAS	1,063	571,030	74.6	-	67.0	6,773	GAS	3,762,100	1,028,000	3,867,440.0	17,502,679	3.07	4.65
27. POLK #2 CC OIL	159	280	0.2	-	17.6	10,857	LGT OIL	520	5,846,154	3,040.0	63,017	22.51	121.19
28. POLK #2 CC TOTAL	**1,063**	**571,310**	**74.6**	**96.9**	**66.9**	**6,775**	**-**	**-**	**-**	**3,870,480.0**	**17,565,696**	**3.07**	**-**
29. POLK STATION TOTAL	**1,283**	**710,780**	**76.9**	**93.9**	**71.3**	**7,439**	**-**	**-**	**-**	**5,287,620.0**	**20,752,069**	**2.92**	**-**
30. BAYSIDE #1	701	309,390	61.3	96.9	63.3	7,443	GAS	2,240,030	1,028,000	2,302,750.0	10,421,447	3.37	4.65
31. BAYSIDE #2	929	302,950	45.3	95.9	46.9	7,716	GAS	2,273,820	1,028,001	2,337,490.0	10,578,649	3.49	4.65
32. BAYSIDE #3	56	890	2.2	98.6	99.3	11,517	GAS	9,980	1,027,054	10,250.0	46,431	5.22	4.65
33. BAYSIDE #4	56	880	2.2	98.6	98.2	11,659	GAS	9,980	1,028,056	10,260.0	46,431	5.28	4.65
34. BAYSIDE #5	56	1,180	2.9	98.6	95.8	11,797	GAS	13,550	1,027,306	13,920.0	63,040	5.34	4.65
35. BAYSIDE #6	56	940	2.3	98.6	98.7	11,713	GAS	10,710	1,028,011	11,010.0	49,827	5.30	4.65
36. BAYSIDE TOTAL	**1,854**	**616,230**	**46.2**	**96.6**	**54.1**	**7,604**	**GAS**	**4,558,070**	**1,027,996**	**4,685,680.0**	**21,205,825**	**3.44**	**4.65**
37. SYSTEM	**4,816**	**1,911,420**	**55.1**	**83.8**	**67.8**	**8,380**	**-**	**-**	**-**	**16,017,850.0**	**62,138,147**	**3.25**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

[1] As burned fuel cost system total includes ignition.
[2] Fuel burned (MM BTU) system total excludes ignition.
[3] AC rating
[4] Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: JULY 2017

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) [2]	AS BURNED FUEL COST ($) [1]	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	270	24.2	-	24.2	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	18.0	4,260	31.8	-	31.8	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR [3]	**21.1**	**4,820**	**30.7**	**-**	**30.7**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	193,720	-	-	-	10,572	COAL	86,230	23,751,015	2,048,050.0	6,876,327	3.55	79.74
7. TOTAL BIG BEND #1	**385**	**193,720**	**67.6**	**80.6**	**86.5**	**10,572**		**-**	**-**	**2,048,050.0**	**6,876,327**	**3.55**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	185,130	-	-	-	10,302	COAL	81,850	23,300,428	1,907,140.0	6,527,048	3.53	79.74
10. TOTAL BIG BEND #2	**385**	**185,130**	**64.6**	**82.0**	**86.0**	**10,302**		**-**	**-**	**1,907,140.0**	**6,527,048**	**3.53**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	144,600	-	-	-	10,354	COAL	65,100	22,998,618	1,497,210.0	5,191,336	3.59	79.74
13. TOTAL BIG BEND #3	**395**	**144,600**	**49.2**	**69.4**	**84.5**	**10,354**		**-**	**-**	**1,497,210.0**	**5,191,336**	**3.59**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	206,950	-	-	-	10,426	COAL	93,810	23,001,173	2,157,740.0	7,484,126	3.62	79.78
16. TOTAL BIG BEND #4	**437**	**206,950**	**63.7**	**81.9**	**81.6**	**10,426**		**-**	**-**	**2,157,740.0**	**7,484,126**	**3.62**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	26,300	-	27,030.0	125,105	-	4.76
18. BIG BEND 1-4 COAL TOTAL	**1,602**	**730,400**	**61.3**	**78.5**	**84.6**	**10,419**	**COAL**	**326,990**	**23,273,311**	**7,610,140.0**	**26,078,837**	**3.57**	**79.75**
19. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	56	560	1.3	-	100.0	11,804	GAS	6,430	1,027,994	6,610.0	30,587	5.46	4.76
21. B.B.C.T.#4 TOTAL	**56**	**560**	**1.3**	**98.3**	**100.0**	**11,804**	**-**	**-**	**-**	**6,610.0**	**30,587**	**5.46**	**-**
22. BIG BEND STATION TOTAL	**1,658**	**730,960**	**59.3**	**79.2**	**84.6**	**10,420**	**-**	**-**	**-**	**7,616,750.0**	**26,234,529**	**3.59**	**-**
23. POLK #1 GASIFIER	220	140,610	85.9	-	97.4	10,206	COAL	52,320	27,428,326	1,435,050.0	3,291,060	2.34	62.90
24. POLK #1 CT GAS [4]	195	0	0.0	-	0.0	0	GAS	2,040	0	0.0	0	0.00	0.00
25. POLK #1 TOTAL	**220**	**140,610**	**85.9**	**79.0**	**97.4**	**10,206**	**-**	**-**	**-**	**1,435,050.0**	**3,291,060**	**2.34**	**-**
26. POLK #2 CC GAS	1,063	539,080	68.2	-	66.6	6,754	GAS	3,541,520	1,027,999	3,640,680.0	16,846,466	3.13	4.76
27. POLK #2 CC OIL	159	220	0.2	-	17.3	10,727	LGT OIL	400	5,900,000	2,360.0	48,306	21.96	120.77
28. POLK #2 CC TOTAL	**1,063**	**539,300**	**68.2**	**96.9**	**66.6**	**6,755**	**-**	**-**	**-**	**3,643,040.0**	**16,894,772**	**3.13**	**-**
29. POLK STATION TOTAL	**1,283**	**679,910**	**71.2**	**93.9**	**71.2**	**7,469**	**-**	**-**	**-**	**5,078,090.0**	**20,185,832**	**2.97**	**-**
30. BAYSIDE #1	701	291,660	55.9	96.9	57.2	7,498	GAS	2,127,260	1,027,998	2,186,820.0	10,119,049	3.47	4.76
31. BAYSIDE #2	929	266,750	38.6	95.9	40.0	7,847	GAS	2,036,210	1,027,998	2,093,220.0	9,685,938	3.63	4.76
32. BAYSIDE #3	56	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
33. BAYSIDE #4	56	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
34. BAYSIDE #5	56	210	0.5	98.6	93.8	12,048	GAS	2,450	1,032,653	2,530.0	11,654	5.55	4.76
35. BAYSIDE #6	56	100	0.2	98.6	89.3	13,200	GAS	1,290	1,023,256	1,320.0	6,136	6.14	4.76
36. BAYSIDE TOTAL	**1,854**	**558,720**	**40.5**	**90.7**	**47.5**	**7,667**	**GAS**	**4,167,210**	**1,028,000**	**4,283,890.0**	**19,822,777**	**3.55**	**4.76**
37. SYSTEM	**4,816**	**1,974,410**	**55.1**	**87.2**	**65.9**	**8,599**	**-**	**-**	**-**	**16,978,730.0**	**66,243,138**	**3.36**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

[1] As burned fuel cost system total includes ignition.
[3] AC rating

[2] Fuel burned (MM BTU) system total excludes ignition.
[4] Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: AUGUST 2017

(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	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	250	22.4	-	22.4	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	18.0	4,110	30.7	-	30.7	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR [3]	**21.1**	**4,650**	**29.6**	**-**	**29.6**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	190,300	-	-	-	10,573	COAL	84,720	23,749,882	2,012,090.0	6,752,881	3.55	79.71
7. TOTAL BIG BEND #1	**385**	**190,300**	**66.4**	**80.6**	**86.4**	**10,573**		**-**	**-**	**2,012,090.0**	**6,752,881**	**3.55**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	197,270	-	-	-	10,277	COAL	87,010	23,300,310	2,027,360.0	6,935,413	3.52	79.71
10. TOTAL BIG BEND #2	**385**	**197,270**	**68.9**	**82.0**	**87.3**	**10,277**		**-**	**-**	**2,027,360.0**	**6,935,413**	**3.52**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	215,640	-	-	-	10,330	COAL	96,850	22,999,174	2,227,470.0	7,719,741	3.58	79.71
13. TOTAL BIG BEND #3	**395**	**215,640**	**73.4**	**86.0**	**86.7**	**10,330**		**-**	**-**	**2,227,470.0**	**7,719,741**	**3.58**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	211,940	-	-	-	10,428	COAL	96,090	22,999,688	2,210,040.0	7,660,992	3.61	79.73
16. TOTAL BIG BEND #4	**437**	**211,940**	**65.2**	**81.9**	**81.4**	**10,428**		**-**	**-**	**2,210,040.0**	**7,660,992**	**3.61**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	16,690	-	17,160.0	79,794	-	4.78
18. BIG BEND 1-4 COAL TOTAL	**1,602**	**815,150**	**68.4**	**82.6**	**85.3**	**10,399**	**COAL**	**364,670**	**23,245,564**	**8,476,960.0**	**29,069,027**	**3.57**	**79.71**
19. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	56	950	2.3	-	99.8	11,684	GAS	10,800	1,027,778	11,100.0	51,635	5.44	4.78
21. B.B.C.T.#4 TOTAL	**56**	**950**	**2.3**	**98.3**	**99.8**	**11,684**	**-**	**-**	**-**	**11,100.0**	**51,635**	**5.44**	**-**
22. BIG BEND STATION TOTAL	**1,658**	**816,100**	**66.2**	**83.1**	**85.3**	**10,401**	**-**	**-**	**-**	**8,488,060.0**	**29,200,456**	**3.58**	**-**
23. POLK #1 GASIFIER	220	140,610	85.9	-	97.4	10,206	COAL	52,320	27,428,135	1,435,040.0	3,300,395	2.35	63.08
24. POLK #1 CT GAS [4]	195	3,390	2.3	-	96.6	8,442	GAS	29,890	957,511	28,620.0	133,150	3.93	4.45
25. POLK #1 TOTAL	**220**	**144,000**	**88.0**	**79.0**	**97.4**	**10,164**	**-**	**-**	**-**	**1,463,660.0**	**3,433,545**	**2.38**	**-**
26. POLK #2 CC GAS	1,063	527,050	66.6	-	64.1	6,760	GAS	3,465,830	1,027,993	3,562,850.0	16,570,024	3.14	4.78
27. POLK #2 CC OIL	159	280	0.2	-	17.6	10,571	LGT OIL	520	5,692,308	2,960.0	62,518	22.33	120.23
28. POLK #2 CC TOTAL	**1,063**	**527,330**	**66.7**	**96.9**	**64.0**	**6,762**	**-**	**-**	**-**	**3,565,810.0**	**16,632,542**	**3.15**	**-**
29. POLK STATION TOTAL	**1,283**	**671,330**	**70.3**	**93.9**	**69.1**	**7,492**	**-**	**-**	**-**	**5,029,470.0**	**20,066,087**	**2.99**	**-**
30. BAYSIDE #1	701	256,820	49.2	96.9	56.5	7,509	GAS	1,875,970	1,028,002	1,928,500.0	8,968,954	3.49	4.78
31. BAYSIDE #2	929	265,210	38.4	95.9	39.8	7,859	GAS	2,027,560	1,027,999	2,084,330.0	9,693,700	3.66	4.78
32. BAYSIDE #3	56	280	0.7	98.6	100.0	11,750	GAS	3,210	1,024,922	3,290.0	15,347	5.48	4.78
33. BAYSIDE #4	56	280	0.7	98.6	100.0	11,750	GAS	3,210	1,024,922	3,290.0	15,347	5.48	4.78
34. BAYSIDE #5	56	630	1.5	98.6	93.8	11,857	GAS	7,260	1,028,926	7,470.0	34,710	5.51	4.78
35. BAYSIDE #6	56	430	1.0	98.6	96.0	11,837	GAS	4,940	1,030,364	5,090.0	23,618	5.49	4.78
36. BAYSIDE TOTAL	**1,854**	**523,650**	**38.0**	**96.6**	**46.6**	**7,700**	**GAS**	**3,922,150**	**1,028,000**	**4,031,970.0**	**18,751,676**	**3.58**	**4.78**
37. SYSTEM	**4,816**	**2,015,730**	**56.3**	**90.8**	**66.0**	**8,706**	**-**	**-**	**-**	**17,549,500.0**	**68,018,219**	**3.37**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

[1] As burned fuel cost system total includes ignition.
[2] Fuel burned (MM BTU) system total excludes ignition.
[3] AC rating
[4] Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: SEPTEMBER 2017

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU) [2]	AS BURNED FUEL COST ($) [1]	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. TIA SOLAR	1.6	260	22.6	-	22.6	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	210	19.4	-	19.4	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	18.0	3,390	26.2	-	26.2	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR [3]	**21.1**	**3,860**	**25.4**	**-**	**25.4**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	188,830	-	-	-	10,548	COAL	83,860	23,750,298	1,991,700.0	6,724,347	3.56	80.19
7. TOTAL BIG BEND #1	**385**	**188,830**	**68.1**	**80.6**	**87.4**	**10,548**		**-**	**-**	**1,991,700.0**	**6,724,347**	**3.56**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	202,670	-	-	-	10,235	COAL	89,030	23,299,562	2,074,360.0	7,138,902	3.52	80.19
10. TOTAL BIG BEND #2	**385**	**202,670**	**73.1**	**82.0**	**91.4**	**10,235**		**-**	**-**	**2,074,360.0**	**7,138,902**	**3.52**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	193,960	-	-	-	10,340	COAL	87,190	23,001,032	2,005,460.0	6,991,361	3.60	80.19
13. TOTAL BIG BEND #3	**395**	**193,960**	**68.2**	**86.0**	**85.8**	**10,340**		**-**	**-**	**2,005,460.0**	**6,991,361**	**3.60**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	179,970	-	-	-	10,397	COAL	81,360	22,999,017	1,871,200.0	6,526,175	3.63	80.21
16. TOTAL BIG BEND #4	**437**	**179,970**	**57.2**	**81.9**	**85.1**	**10,397**		**-**	**-**	**1,871,200.0**	**6,526,175**	**3.63**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	18,360	-	18,880.0	88,856	-	4.84
18. BIG BEND 1-4 COAL TOTAL	**1,602**	**765,430**	**66.4**	**82.6**	**87.5**	**10,377**	**COAL**	**341,440**	**23,262,418**	**7,942,720.0**	**27,380,785**	**3.58**	**80.19**
19. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	56	1,840	4.6	-	99.6	11,685	GAS	20,910	1,028,216	21,500.0	101,198	5.50	4.84
21. B.B.C.T.#4 TOTAL	**56**	**1,840**	**4.6**	**98.3**	**99.6**	**11,685**	**-**	**-**	**-**	**21,500.0**	**101,198**	**5.50**	**-**
22. BIG BEND STATION TOTAL	**1,658**	**767,270**	**64.3**	**83.1**	**87.5**	**10,380**	**-**	**-**	**-**	**7,964,220.0**	**27,570,839**	**3.59**	**-**
23. POLK #1 GASIFIER	220	135,970	85.8	-	97.5	10,205	COAL	50,580	27,432,384	1,387,530.0	3,192,459	2.35	63.12
24. POLK #1 CT GAS [4]	195	0	0.0	-	0.0	0	GAS	2,040	0	0.0	0	0.00	0.00
25. POLK #1 TOTAL	**220**	**135,970**	**85.8**	**79.0**	**97.5**	**10,205**	**-**	**-**	**-**	**1,387,530.0**	**3,192,459**	**2.35**	**-**
26. POLK #2 CC GAS	1,063	515,990	67.4	-	64.0	6,760	GAS	3,392,990	1,027,996	3,487,980.0	16,420,988	3.18	4.84
27. POLK #2 CC OIL	159	220	0.2	-	17.3	11,091	LGT OIL	420	5,809,524	2,440.0	50,316	22.87	119.80
28. POLK #2 CC TOTAL	**1,063**	**516,210**	**67.4**	**96.9**	**63.9**	**6,762**	**-**	**-**	**-**	**3,490,420.0**	**16,471,304**	**3.19**	**-**
29. POLK STATION TOTAL	**1,283**	**652,180**	**70.6**	**93.9**	**68.8**	**7,479**	**-**	**-**	**-**	**4,877,950.0**	**19,663,763**	**3.02**	**-**
30. BAYSIDE #1	701	259,030	51.3	96.9	54.2	7,533	GAS	1,898,250	1,027,999	1,951,400.0	9,186,924	3.55	4.84
31. BAYSIDE #2	929	176,990	26.5	73.6	32.9	8,052	GAS	1,386,240	1,028,004	1,425,060.0	6,708,959	3.79	4.84
32. BAYSIDE #3	56	470	1.2	98.6	93.3	12,085	GAS	5,530	1,027,125	5,680.0	26,763	5.69	4.84
33. BAYSIDE #4	56	220	0.5	98.6	98.2	11,727	GAS	2,510	1,027,888	2,580.0	12,148	5.52	4.84
34. BAYSIDE #5	56	1,300	3.2	98.6	92.9	11,792	GAS	14,910	1,028,169	15,330.0	72,160	5.55	4.84
35. BAYSIDE #6	56	1,040	2.6	98.6	92.9	11,750	GAS	11,880	1,028,620	12,220.0	57,495	5.53	4.84
36. BAYSIDE TOTAL	**1,854**	**439,050**	**32.9**	**85.4**	**43.1**	**7,772**	**GAS**	**3,319,320**	**1,028,003**	**3,412,270.0**	**16,064,449**	**3.66**	**4.84**
37. SYSTEM	**4,816**	**1,862,360**	**53.7**	**86.5**	**65.5**	**8,728**	**-**	**-**	**-**	**16,254,440.0**	**63,299,051**	**3.40**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

[1] As burned fuel cost system total includes ignition.
[3] AC rating

[2] Fuel burned (MM BTU) system total excludes ignition.
[4] Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: OCTOBER 2017

(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	1.6	290	24.4	-	24.4	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	210	18.8	-	18.8	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	18.0	3,490	26.1	-	26.1	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR [3]	**21.1**	**3,990**	**25.4**	**-**	**25.4**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	189,850	-	-	-	10,553	COAL	84,360	23,750,237	2,003,570.0	6,847,690	3.61	81.17
7. TOTAL BIG BEND #1	**385**	**189,850**	**66.3**	**80.6**	**87.1**	**10,553**		**-**	**-**	**2,003,570.0**	**6,847,690**	**3.61**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	202,330	-	-	-	10,281	COAL	89,280	23,298,947	2,080,130.0	7,247,055	3.58	81.17
10. TOTAL BIG BEND #2	**385**	**202,330**	**70.6**	**82.0**	**87.9**	**10,281**		**-**	**-**	**2,080,130.0**	**7,247,055**	**3.58**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	201,820	-	-	-	10,394	COAL	91,200	23,001,096	2,097,700.0	7,402,906	3.67	81.17
13. TOTAL BIG BEND #3	**395**	**201,820**	**68.7**	**86.0**	**81.6**	**10,394**		**-**	**-**	**2,097,700.0**	**7,402,906**	**3.67**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	173,280	-	-	-	10,414	COAL	78,460	22,999,873	1,804,570.0	6,370,765	3.68	81.20
16. TOTAL BIG BEND #4	**437**	**173,280**	**53.3**	**81.9**	**82.1**	**10,414**		**-**	**-**	**1,804,570.0**	**6,370,765**	**3.68**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	17,120	-	17,590.0	87,442	-	5.11
18. BIG BEND 1-4 COAL TOTAL	**1,602**	**767,280**	**64.4**	**82.6**	**84.6**	**10,408**	**COAL**	**343,300**	**23,262,365**	**7,985,970.0**	**27,868,416**	**3.63**	**81.18**
19. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	56	4,000	9.6	-	97.8	11,700	GAS	45,520	1,028,120	46,800.0	232,497	5.81	5.11
21. B.B.C.T.#4 TOTAL	**56**	**4,000**	**9.6**	**98.3**	**97.8**	**11,700**	**-**	**-**	**-**	**46,800.0**	**232,497**	**5.81**	**-**
22. BIG BEND STATION TOTAL	**1,658**	**771,280**	**62.5**	**83.1**	**84.7**	**10,415**	**-**	**-**	**-**	**8,032,770.0**	**28,188,355**	**3.65**	**-**
23. POLK #1 GASIFIER	220	140,610	85.9	-	97.4	10,206	COAL	52,320	27,428,326	1,435,050.0	3,484,721	2.48	66.60
24. POLK #1 CT GAS [4]	195	5,810	4.0	-	96.1	8,253	GAS	48,690	984,802	47,950.0	238,269	4.10	4.89
25. POLK #1 TOTAL	**220**	**146,420**	**89.5**	**79.0**	**97.4**	**10,128**	**-**	**-**	**-**	**1,483,000.0**	**3,722,990**	**2.54**	**-**
26. POLK #2 CC GAS	1,063	482,650	61.0	-	51.1	6,847	GAS	3,214,780	1,027,993	3,304,770.0	16,419,751	3.40	5.11
27. POLK #2 CC OIL	159	280	0.2	-	17.6	10,571	LGT OIL	520	5,692,308	2,960.0	62,028	22.15	119.28
28. POLK #2 CC TOTAL	**1,063**	**482,930**	**61.1**	**9.4**	**51.1**	**6,849**	**-**	**-**	**-**	**3,307,730.0**	**16,481,779**	**3.41**	**-**
29. POLK STATION TOTAL	**1,283**	**629,350**	**65.9**	**21.3**	**57.4**	**7,612**	**-**	**-**	**-**	**4,790,730.0**	**20,204,769**	**3.21**	**-**
30. BAYSIDE #1	701	239,270	45.9	96.9	46.9	7,639	GAS	1,777,890	1,027,999	1,827,670.0	9,080,718	3.80	5.11
31. BAYSIDE #2	929	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
32. BAYSIDE #3	56	2,070	5.0	98.6	94.8	11,899	GAS	23,960	1,027,963	24,630.0	122,378	5.91	5.11
33. BAYSIDE #4	56	1,570	3.8	98.6	96.7	11,764	GAS	17,970	1,027,824	18,470.0	91,783	5.85	5.11
34. BAYSIDE #5	56	2,830	6.8	98.6	93.6	11,834	GAS	32,590	1,027,616	33,490.0	166,456	5.88	5.11
35. BAYSIDE #6	56	2,340	5.6	98.6	95.0	11,756	GAS	26,750	1,028,411	27,510.0	136,628	5.84	5.11
36. BAYSIDE TOTAL	**1,854**	**248,080**	**18.0**	**48.5**	**47.7**	**7,787**	**GAS**	**1,879,160**	**1,027,997**	**1,931,770.0**	**9,597,963**	**3.87**	**5.11**
37. SYSTEM	**4,816**	**1,652,700**	**46.1**	**53.0**	**65.4**	**8,928**	**-**	**-**	**-**	**14,755,270.0**	**57,991,087**	**3.51**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

[1] As burned fuel cost system total includes ignition.
[3] AC rating

[2] Fuel burned (MM BTU) system total excludes ignition.
[4] Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: NOVEMBER 2017

(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	1.6	270	23.4	-	23.4	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	170	15.7	-	15.7	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	18.0	2,960	22.8	-	22.8	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR [3]	**21.1**	**3,400**	**22.4**	**-**	**22.4**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	102,010	-	-	-	10,527	COAL	45,210	23,752,488	1,073,850.0	3,698,366	3.63	81.80
7. TOTAL BIG BEND #1	**385**	**102,010**	**36.8**	**80.6**	**88.6**	**10,527**		**-**	**-**	**1,073,850.0**	**3,698,366**	**3.63**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	164,580	-	-	-	10,275	COAL	72,570	23,301,502	1,690,990.0	5,936,529	3.61	81.80
10. TOTAL BIG BEND #2	**385**	**164,580**	**59.4**	**82.0**	**87.4**	**10,275**		**-**	**-**	**1,690,990.0**	**5,936,529**	**3.61**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	168,800	-	-	-	10,346	COAL	75,930	22,999,605	1,746,360.0	6,211,390	3.68	81.80
13. TOTAL BIG BEND #3	**395**	**168,800**	**59.4**	**83.1**	**85.3**	**10,346**		**-**	**-**	**1,746,360.0**	**6,211,390**	**3.68**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	94,630	-	-	-	10,434	COAL	42,930	22,999,068	987,350.0	3,515,913	3.72	81.90
16. TOTAL BIG BEND #4	**437**	**94,630**	**30.1**	**54.6**	**81.1**	**10,434**		**-**	**-**	**987,350.0**	**3,515,913**	**3.72**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	27,550	-	28,320.0	134,460	-	4.88
18. BIG BEND 1-4 COAL TOTAL	**1,602**	**530,020**	**46.0**	**74.5**	**85.8**	**10,374**	**COAL**	**236,640**	**23,235,928**	**5,498,550.0**	**19,362,198**	**3.65**	**81.82**
19. B.B.C.T.#4 OIL	56	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	56	560	1.4	-	100.0	11,732	GAS	6,400	1,026,563	6,570.0	31,236	5.58	4.88
21. B.B.C.T.#4 TOTAL	**56**	**560**	**1.4**	**98.3**	**100.0**	**11,732**	**-**	**-**	**-**	**6,570.0**	**31,236**	**5.58**	**-**
22. BIG BEND STATION TOTAL	**1,658**	**530,580**	**44.4**	**75.3**	**85.8**	**10,376**	**-**	**-**	**-**	**5,505,120.0**	**19,527,894**	**3.68**	**-**
23. POLK #1 GASIFIER	220	104,240	65.8	-	97.5	10,264	COAL	38,780	27,589,479	1,069,920.0	2,641,560	2.53	68.12
24. POLK #1 CT GAS [4]	195	3,500	2.5	-	99.7	8,129	GAS	35,270	806,635	28,450.0	135,094	3.86	3.83
25. POLK #1 TOTAL	**220**	**107,740**	**68.0**	**79.0**	**97.6**	**10,195**	**-**	**-**	**-**	**1,098,370.0**	**2,776,654**	**2.58**	**-**
26. POLK #2 CC GAS	1,063	503,210	65.7	-	65.1	6,746	GAS	3,302,310	1,027,996	3,394,760.0	16,117,185	3.20	4.88
27. POLK #2 CC OIL	159	220	0.2	-	17.3	11,000	LGT OIL	420	5,761,905	2,420.0	49,928	22.69	118.88
28. POLK #2 CC TOTAL	**1,063**	**503,430**	**65.8**	**96.9**	**65.0**	**6,748**	**-**	**-**	**-**	**3,397,180.0**	**16,167,113**	**3.21**	**-**
29. POLK STATION TOTAL	**1,283**	**611,170**	**66.2**	**93.9**	**69.1**	**7,356**	**-**	**-**	**-**	**4,495,550.0**	**18,943,767**	**3.10**	**-**
30. BAYSIDE #1	701	158,640	31.4	84.0	43.9	7,688	GAS	1,186,480	1,027,999	1,219,700.0	5,790,710	3.65	4.88
31. BAYSIDE #2	929	58,660	8.8	25.6	27.2	8,315	GAS	474,490	1,027,988	487,770.0	2,315,786	3.95	4.88
32. BAYSIDE #3	56	320	0.8	98.6	95.2	11,844	GAS	3,690	1,027,100	3,790.0	18,009	5.63	4.88
33. BAYSIDE #4	56	160	0.4	98.6	95.2	12,125	GAS	1,890	1,026,455	1,940.0	9,224	5.77	4.88
34. BAYSIDE #5	56	370	0.9	98.6	94.4	11,865	GAS	4,270	1,028,103	4,390.0	20,840	5.63	4.88
35. BAYSIDE #6	56	320	0.8	98.6	95.2	11,656	GAS	3,630	1,027,548	3,730.0	17,717	5.54	4.88
36. BAYSIDE TOTAL	**1,854**	**218,470**	**16.4**	**56.5**	**37.8**	**7,879**	**GAS**	**1,674,450**	**1,027,991**	**1,721,320.0**	**8,172,286**	**3.74**	**4.88**
37. SYSTEM	**4,816**	**1,363,620**	**39.3**	**72.7**	**65.5**	**8,596**	**-**	**-**	**-**	**11,721,990.0**	**46,643,947**	**3.42**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

[1] As burned fuel cost system total includes ignition.
[2] Fuel burned (MM BTU) system total excludes ignition.
[3] AC rating
[4] Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.

SCHEDULE E4

TAMPA ELECTRIC COMPANY
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD: DECEMBER 2017

(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	1.6	260	21.8	-	21.8	-	SOLAR	-	-	-	-	-	-
2. LEGOLAND SOLAR	1.5	150	13.4	-	13.4	-	SOLAR	-	-	-	-	-	-
3. BIG BEND SOLAR	18.0	2,640	19.7	-	19.7	-	SOLAR	-	-	-	-	-	-
4. TOTAL SOLAR [3]	**21.1**	**3,050**	**19.4**	**-**	**19.4**	**-**	**SOLAR**	**-**	**-**	**-**	**-**	**-**	**-**
5. B.B.#1 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
6. B.B.#1 COAL	-	109,760	-	-	-	10,397	COAL	48,050	23,748,803	1,141,130.0	3,941,552	3.59	82.03
7. TOTAL BIG BEND #1	**395**	**109,760**	**37.3**	**54.6**	**91.4**	**10,397**		**-**	**-**	**1,141,130.0**	**3,941,552**	**3.59**	**-**
8. B.B.#2 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
9. B.B.#2 COAL	-	109,040	-	-	-	10,293	COAL	48,170	23,299,772	1,122,350.0	3,951,398	3.62	82.03
10. TOTAL BIG BEND #2	**395**	**109,040**	**37.1**	**55.5**	**83.1**	**10,293**		**-**	**-**	**1,122,350.0**	**3,951,398**	**3.62**	**-**
11. B.B.#3 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
12. B.B.#3 COAL	-	124,970	-	-	-	10,275	COAL	55,830	22,999,284	1,284,050.0	4,579,750	3.66	82.03
13. TOTAL BIG BEND #3	**400**	**124,970**	**42.0**	**61.0**	**87.5**	**10,275**		**-**	**-**	**1,284,050.0**	**4,579,750**	**3.66**	**-**
14. B.B.#4 NAT GAS CO-FIRE	-	0	-	-	-	0	NG CO-FIRE	0	0	0.0	0	0.00	0.00
15. B.B.#4 COAL	-	219,450	-	-	-	10,365	COAL	98,890	23,000,506	2,274,520.0	8,114,894	3.70	82.06
16. TOTAL BIG BEND #4	**442**	**219,450**	**66.7**	**81.9**	**81.1**	**10,365**		**-**	**-**	**2,274,520.0**	**8,114,894**	**3.70**	**-**
17. B.B. 1-4 IGNITION	-	-	-	-	-	-	GAS	18,780	-	19,310.0	93,985	-	5.00
18. BIG BEND 1-4 COAL TOTAL	**1,632**	**563,220**	**46.4**	**63.8**	**84.8**	**10,337**	**COAL**	**250,940**	**23,200,964**	**5,822,050.0**	**20,587,594**	**3.66**	**82.04**
19. B.B.C.T.#4 OIL	61	0	0.0	-	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
20. B.B.C.T.#4 GAS	61	90	0.2	-	73.8	13,111	GAS	1,150	1,026,087	1,180.0	5,755	6.39	5.00
21. B.B.C.T.#4 TOTAL	**61**	**90**	**0.2**	**98.3**	**73.8**	**13,111**	**-**	**-**	**-**	**1,180.0**	**5,755**	**6.39**	**-**
22. BIG BEND STATION TOTAL	**1,693**	**563,310**	**44.7**	**65.0**	**84.8**	**10,338**	**-**	**-**	**-**	**5,823,230.0**	**20,687,334**	**3.67**	**-**
23. POLK #1 GASIFIER	220	140,610	85.9	-	97.4	10,206	COAL	52,320	27,428,135	1,435,040.0	3,494,183	2.49	66.78
24. POLK #1 CT GAS [4]	195	0	0.0	-	0.0	0	GAS	2,040	0	0.0	0	0.00	0.00
25. POLK #1 TOTAL	**220**	**140,610**	**85.9**	**79.0**	**97.4**	**10,206**	**-**	**-**	**-**	**1,435,040.0**	**3,494,183**	**2.49**	**-**
26. POLK #2 CC GAS	1,195	498,440	56.1	-	56.9	6,743	GAS	3,269,500	1,028,001	3,361,050.0	16,362,282	3.28	5.00
27. POLK #2 CC OIL	187	220	0.2	-	14.7	10,727	LGT OIL	400	5,900,000	2,360.0	47,397	21.54	118.49
28. POLK #2 CC TOTAL	**1,195**	**498,660**	**56.1**	**96.9**	**56.8**	**6,745**	**-**	**-**	**-**	**3,363,410.0**	**16,409,679**	**3.29**	**-**
29. POLK STATION TOTAL	**1,415**	**639,270**	**60.7**	**94.2**	**62.6**	**7,506**	**-**	**-**	**-**	**4,798,450.0**	**19,903,862**	**3.11**	**-**
30. BAYSIDE #1	792	85,810	14.6	71.9	33.9	7,675	GAS	640,690	1,028,001	658,630.0	3,206,346	3.74	5.00
31. BAYSIDE #2	1,047	166,010	21.3	95.9	22.1	8,315	GAS	1,342,770	1,028,002	1,380,370.0	6,719,921	4.05	5.00
32. BAYSIDE #3	61	60	0.1	98.6	98.4	11,500	GAS	680	1,014,706	690.0	3,403	5.67	5.00
33. BAYSIDE #4	61	60	0.1	98.6	98.4	10,667	GAS	630	1,015,873	640.0	3,153	5.26	5.00
34. BAYSIDE #5	61	60	0.1	98.6	98.4	11,500	GAS	680	1,014,706	690.0	3,403	5.67	5.00
35. BAYSIDE #6	61	60	0.1	98.6	98.4	11,500	GAS	680	1,014,706	690.0	3,403	5.67	5.00
36. BAYSIDE TOTAL	**2,083**	**252,060**	**16.3**	**87.1**	**25.1**	**8,100**	**GAS**	**1,986,130**	**1,027,984**	**2,041,710.0**	**9,939,629**	**3.94**	**5.00**
37. SYSTEM	**5,212**	**1,457,690**	**37.6**	**81.5**	**54.2**	**8,687**	**-**	**-**	**-**	**12,663,390.0**	**50,530,825**	**3.47**	**-**

LEGEND:
B.B. = BIG BEND NG = NATURAL GAS
C.T. = COMBUSTION TURBINE CC = COMBINED CYCLE

[1] As burned fuel cost system total includes ignition.
[2] Fuel burned (MM BTU) system total excludes ignition.
[3] AC rating
[4] Includes ignition units burned for Polk #1 Gasifier - ignition dollars included in line 23.

SCHEDULE E5

TAMPA ELECTRIC COMPANY
SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH JUNE 2017

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17
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)	420	440	400	520	400	520
16. UNIT COST ($/BBL)	72.77	73.11	73.13	72.90	73.04	73.32
17. AMOUNT ($)	30,564	32,170	29,251	37,910	29,215	38,128
18. BURNED:						
19. UNITS (BBL)	420	440	400	520	400	520
20. UNIT COST ($/BBL)	123.70	123.21	122.76	122.18	121.75	121.19
21. AMOUNT ($)	51,955	54,211	49,104	63,536	48,699	63,017
22. ENDING INVENTORY:						
23. UNITS (BBL)	44,488	44,488	44,488	44,488	44,488	44,488
24. UNIT COST ($/BBL)	123.70	123.21	122.76	122.18	121.75	121.19
25. AMOUNT ($)	5,503,265	5,481,224	5,461,371	5,435,745	5,416,262	5,391,373
26. DAYS SUPPLY: NORMAL	3,018	3,274	3,593	3,941	4,511	5,074
27. DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6
COAL						
28. PURCHASES:						
29. UNITS (TONS)	283,343	253,333	288,333	293,333	313,333	343,333
30. UNIT COST ($/TON)	72.32	74.59	75.25	75.25	75.99	76.10
31. AMOUNT ($)	20,492,710	18,896,679	21,696,295	22,073,629	23,810,294	26,126,974
32. BURNED:						
33. UNITS (TONS)	338,050	257,240	319,890	363,620	285,430	308,670
34. UNIT COST ($/TON)	70.86	71.25	75.36	74.22	73.18	74.94
35. AMOUNT ($)	23,952,767	18,327,084	24,107,497	26,987,734	20,887,421	23,132,938
36. ENDING INVENTORY:						
37. UNITS (TONS)	421,730	417,823	386,266	315,979	343,882	378,545
38. UNIT COST ($/TON)	62.41	64.98	64.67	64.12	67.84	70.21
39. AMOUNT ($)	26,319,598	27,149,491	24,980,731	20,259,600	23,330,269	26,577,625
40. DAYS SUPPLY:	41	40	37	30	32	32
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	4,707,170	4,785,900	4,837,590	4,729,890	7,955,199	8,395,400
43. UNIT COST ($/MCF)	5.33	5.10	5.15	5.19	4.63	4.66
44. AMOUNT ($)	25,067,627	24,408,980	24,915,929	24,524,982	36,822,910	39,090,182
45. BURNED:						
46. UNITS (MCF)	4,707,170	4,785,900	4,837,590	4,729,890	7,663,370	8,395,400
47. UNIT COST ($/MCF)	5.28	5.08	5.13	5.22	4.68	4.64
48. AMOUNT ($)	24,844,669	24,299,192	24,816,367	24,681,408	35,893,394	38,942,192
49. ENDING INVENTORY:						
50. UNITS (MCF)	875,486	875,486	875,486	875,486	1,167,315	1,167,315
51. UNIT COST ($/MCF)	3.52	3.50	3.44	3.15	3.11	3.13
52. AMOUNT ($)	3,080,520	3,067,020	3,015,360	2,754,180	3,627,120	3,658,800
53. DAYS SUPPLY:	4	4	4	4	5	5
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 2017 THROUGH DECEMBER 2017

		Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	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)	400	520	420	520	420	400	5,380
16.	UNIT COST ($/BBL)	73.75	74.20	74.71	75.16	75.58	75.94	73.96
17.	AMOUNT ($)	29,499	38,585	31,379	39,081	31,744	30,375	397,901
18.	BURNED:							
19.	UNITS (BBL)	400	520	420	520	420	400	5,380
20.	UNIT COST ($/BBL)	120.77	120.23	119.80	119.28	118.88	118.49	121.01
21.	AMOUNT ($)	48,306	62,518	50,316	62,028	49,928	47,397	651,015
22.	ENDING INVENTORY:							
23.	UNITS (BBL)	44,488	44,488	44,488	44,488	44,488	44,488	44,488
24.	UNIT COST ($/BBL)	120.76	120.23	119.80	119.28	118.88	118.49	118.49
25.	AMOUNT ($)	5,372,567	5,348,634	5,329,696	5,306,749	5,288,565	5,271,542	5,271,542
26.	DAYS SUPPLY: NORMAL	6,059	7,122	9,226	12,118	19,803	40,595	-
27.	DAYS SUPPLY: EMERGENCY	6	6	6	6	6	6	-
	COAL							
28.	PURCHASES:							
29.	UNITS (TONS)	378,333	343,333	343,333	338,836	318,333	303,337	3,800,513
30.	UNIT COST ($/TON)	77.03	78.60	78.71	79.36	79.98	79.99	77.06
31.	AMOUNT ($)	29,144,003	26,987,355	27,022,710	26,888,659	25,460,254	24,262,860	292,862,422
32.	BURNED:							
33.	UNITS (TONS)	379,310	416,990	392,020	395,620	275,420	303,260	4,035,520
34.	UNIT COST ($/TON)	77.76	77.82	78.22	79.47	80.38	79.72	76.26
35.	AMOUNT ($)	29,495,002	32,449,216	30,662,100	31,440,579	22,138,218	24,175,762	307,756,318
36.	ENDING INVENTORY:							
37.	UNITS (TONS)	377,568	303,911	255,224	198,440	241,353	241,430	241,430
38.	UNIT COST ($/TON)	70.06	69.65	69.43	67.31	70.17	71.31	71.31
39.	AMOUNT ($)	26,452,655	21,168,561	17,719,120	13,357,071	16,935,831	17,215,343	17,215,343
40.	DAYS SUPPLY:	29	23	22	19	31	43	-
	NATURAL GAS							
41.	PURCHASES:							
42.	UNITS (MCF)	7,743,500	7,445,360	6,753,620	5,010,718	4,802,789	5,277,600	72,444,736
43.	UNIT COST ($/MCF)	4.76	4.78	4.84	5.19	4.97	5.02	4.92
44.	AMOUNT ($)	36,868,719	35,606,112	32,662,084	25,996,861	23,891,505	26,512,360	356,368,251
45.	BURNED:							
46.	UNITS (MCF)	7,743,500	7,445,360	6,753,620	5,205,270	5,045,980	5,277,600	72,590,650
47.	UNIT COST ($/MCF)	4.74	4.77	4.83	5.09	4.85	4.98	4.90
48.	AMOUNT ($)	36,699,830	35,506,485	32,586,635	26,488,480	24,455,801	26,307,666	355,522,119
49.	ENDING INVENTORY:							
50.	UNITS (MCF)	1,167,315	1,167,315	1,167,315	972,763	729,572	729,572	729,572
51.	UNIT COST ($/MCF)	3.16	3.17	3.15	3.18	3.23	3.36	3.36
52.	AMOUNT ($)	3,692,880	3,702,960	3,679,680	3,090,200	2,354,400	2,454,900	2,454,900
53.	DAYS SUPPLY:	5	4	4	3	2	2	-
	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 2017 THROUGH JUNE 2017

(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-17	SEMINOLE	JURISD. SCH. - D	800.0	0.0	800.0	2.824	2.933	22,590.00	23,460.00	870.00
	VARIOUS	JURISD. MKT. BASE	940.0	0.0	940.0	2.637	2.901	24,788.43	27,270.00	2,481.57
	TOTAL		**1,740.0**	**0.0**	**1,740.0**	**2.723**	**2.916**	**47,378.43**	**50,730.00**	**3,351.57**
Feb-17	SEMINOLE	JURISD. SCH. - D	680.0	0.0	680.0	2.803	2.911	19,060.00	19,794.00	734.00
	VARIOUS	JURISD. MKT. BASE	990.0	0.0	990.0	2.695	2.965	26,679.15	29,350.00	2,670.85
	TOTAL		**1,670.0**	**0.0**	**1,670.0**	**2.739**	**2.943**	**45,739.15**	**49,144.00**	**3,404.85**
Mar-17	SEMINOLE	JURISD. SCH. - D	870.0	0.0	870.0	2.792	2.899	24,290.00	25,225.00	935.00
	VARIOUS	JURISD. MKT. BASE	940.0	0.0	940.0	2.794	3.073	26,261.01	28,890.00	2,628.99
	TOTAL		**1,810.0**	**0.0**	**1,810.0**	**2.793**	**2.990**	**50,551.01**	**54,115.00**	**3,563.99**
Apr-17	SEMINOLE	JURISD. SCH. - D	1,080.0	0.0	1,080.0	2.654	2.756	28,660.00	29,763.00	1,103.00
	VARIOUS	JURISD. MKT. BASE	1,130.0	0.0	1,130.0	3.554	3.910	40,159.62	44,180.00	4,020.38
	TOTAL		**2,210.0**	**0.0**	**2,210.0**	**3.114**	**3.346**	**68,819.62**	**73,943.00**	**5,123.38**
May-17	SEMINOLE	JURISD. SCH. - D	940.0	0.0	940.0	2.590	2.690	24,350.00	25,287.00	937.00
	VARIOUS	JURISD. MKT. BASE	900.0	0.0	900.0	2.495	2.744	22,452.30	24,700.00	2,247.70
	TOTAL		**1,840.0**	**0.0**	**1,840.0**	**2.544**	**2.717**	**46,802.30**	**49,987.00**	**3,184.70**
Jun-17	SEMINOLE	JURISD. SCH. - D	990.0	0.0	990.0	2.773	2.879	27,450.00	28,507.00	1,057.00
	VARIOUS	JURISD. MKT. BASE	1,160.0	0.0	1,160.0	3.107	3.418	36,041.85	39,650.00	3,608.15
	TOTAL		**2,150.0**	**0.0**	**2,150.0**	**2.953**	**3.170**	**63,491.85**	**68,157.00**	**4,665.15**

SCHEDULE E6

TAMPA ELECTRIC COMPANY
POWER SOLD
ESTIMATED FOR THE PERIOD: JULY 2017 THROUGH DECEMBER 2017

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH		CENTS/KWH				
		TYPE	TOTAL	WHEELED	MWH	(A)	(B)	TOTAL $		
		&	MWH	FROM	FROM OWN	FUEL	TOTAL	FOR FUEL	TOTAL COST	GAINS ON
MONTH	SOLD TO	SCHEDULE	SOLD	OTHER SYSTEMS	GENERATION	COST	COST	ADJUSTMENT	$	SALES
Jul-17	SEMINOLE	JURISD. SCH. - D	1,010.0	0.0	1,010.0	2.651	2.754	26,780.00	27,811.00	1,031.00
	VARIOUS	JURISD. MKT. BASE	900.0	0.0	900.0	2.625	2.888	23,624.91	25,990.00	2,365.09
	TOTAL		**1,910.0**	**0.0**	**1,910.0**	**2.639**	**2.817**	**50,404.91**	**53,801.00**	**3,396.09**
Aug-17	SEMINOLE	JURISD. SCH. - D	1,010.0	0.0	1,010.0	2.736	2.841	27,630.00	28,694.00	1,064.00
	VARIOUS	JURISD. MKT. BASE	1,130.0	0.0	1,130.0	3.507	3.858	39,632.40	43,600.00	3,967.60
	TOTAL		**2,140.0**	**0.0**	**2,140.0**	**3.143**	**3.378**	**67,262.40**	**72,294.00**	**5,031.60**
Sep-17	SEMINOLE	JURISD. SCH. - D	1,000.0	0.0	1,000.0	2.683	2.786	26,830.00	27,863.00	1,033.00
	VARIOUS	JURISD. MKT. BASE	930.0	0.0	930.0	2.949	3.244	27,424.53	30,170.00	2,745.47
	TOTAL		**1,930.0**	**0.0**	**1,930.0**	**2.811**	**3.007**	**54,254.53**	**58,033.00**	**3,778.47**
Oct-17	SEMINOLE	JURISD. SCH. - D	730.0	0.0	730.0	2.918	3.030	21,300.00	22,120.00	820.00
	VARIOUS	JURISD. MKT. BASE	1,130.0	0.0	1,130.0	4.809	5.290	54,340.02	59,780.00	5,439.98
	TOTAL		**1,860.0**	**0.0**	**1,860.0**	**4.067**	**4.403**	**75,640.02**	**81,900.00**	**6,259.98**
Nov-17	SEMINOLE	JURISD. SCH. - D	660.0	0.0	660.0	2.673	2.776	17,640.00	18,319.00	679.00
	VARIOUS	JURISD. MKT. BASE	930.0	0.0	930.0	2.599	2.859	24,170.31	26,590.00	2,419.69
	TOTAL		**1,590.0**	**0.0**	**1,590.0**	**2.630**	**2.824**	**41,810.31**	**44,909.00**	**3,098.69**
Dec-17	SEMINOLE	JURISD. SCH. - D	570.0	0.0	570.0	2.740	2.846	15,620.00	16,221.00	601.00
	VARIOUS	JURISD. MKT. BASE	900.0	0.0	900.0	2.593	2.852	23,334.03	25,670.00	2,335.97
	TOTAL		**1,470.0**	**0.0**	**1,470.0**	**2.650**	**2.850**	**38,954.03**	**41,891.00**	**2,936.97**
TOTAL	SEMINOLE	JURISD. SCH. - D	10,340.0	0.0	10,340.0	2.729	2.834	282,200.00	293,064.00	10,864.00
Jan-17	VARIOUS	JURISD. MKT. BASE	11,980.0	0.0	11,980.0	3.079	3.388	368,908.56	405,840.00	36,931.44
THRU	**TOTAL**		**22,320.0**	**0.0**	**22,320.0**	**2.917**	**3.131**	**651,108.56**	**698,904.00**	**47,795.44**
Dec-17										

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TAMPA ELECTRIC COMPANY
PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

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
Jan-17									
	PASCO COGEN	SCH. - D	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-17									
	PASCO COGEN	SCH. - D	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-17									
	PASCO COGEN	SCH. - D	780.0	0.0	0.0	780.0	4.740	4.740	36,970.00
	TOTAL		**780.0**	**0.0**	**0.0**	**780.0**	**4.740**	**4.740**	**36,970.00**
Apr-17									
	PASCO COGEN	SCH. - D	1,900.0	0.0	0.0	1,900.0	4.956	4.956	94,160.00
	TOTAL		**1,900.0**	**0.0**	**0.0**	**1,900.0**	**4.956**	**4.956**	**94,160.00**
May-17									
	PASCO COGEN	SCH. - D	910.0	0.0	0.0	910.0	4.586	4.586	41,730.00
	TOTAL		**910.0**	**0.0**	**0.0**	**910.0**	**4.586**	**4.586**	**41,730.00**
Jun-17									
	PASCO COGEN	SCH. - D	4,520.0	0.0	0.0	4,520.0	4.462	4.462	201,690.00
	TOTAL		**4,520.0**	**0.0**	**0.0**	**4,520.0**	**4.462**	**4.462**	**201,690.00**
Jul-17									
	PASCO COGEN	SCH. - D	1,470.0	0.0	0.0	1,470.0	4.582	4.582	67,350.00
	TOTAL		**1,470.0**	**0.0**	**0.0**	**1,470.0**	**4.582**	**4.582**	**67,350.00**
Aug-17									
	PASCO COGEN	SCH. - D	2,180.0	0.0	0.0	2,180.0	4.556	4.556	99,330.00
	TOTAL		**2,180.0**	**0.0**	**0.0**	**2,180.0**	**4.556**	**4.556**	**99,330.00**
Sep-17									
	PASCO COGEN	SCH. - D	3,750.0	0.0	0.0	3,750.0	4.540	4.540	170,240.00
	TOTAL		**3,750.0**	**0.0**	**0.0**	**3,750.0**	**4.540**	**4.540**	**170,240.00**
Oct-17									
	PASCO COGEN	SCH. - D	8,470.0	0.0	0.0	8,470.0	4.707	4.707	398,720.00
	TOTAL		**8,470.0**	**0.0**	**0.0**	**8,470.0**	**4.707**	**4.707**	**398,720.00**
Nov-17									
	PASCO COGEN	SCH. - D	1,140.0	0.0	0.0	1,140.0	4.752	4.752	54,170.00
	TOTAL		**1,140.0**	**0.0**	**0.0**	**1,140.0**	**4.752**	**4.752**	**54,170.00**
Dec-17									
	PASCO COGEN	SCH. - D	170.0	0.0	0.0	170.0	4.735	4.735	8,050.00
	TOTAL		**170.0**	**0.0**	**0.0**	**170.0**	**4.735**	**4.735**	**8,050.00**
TOTAL									
Jan-17	PASCO COGEN	SCH. - D	25,290.0	0.0	0.0	25,290.0	4.636	4.636	1,172,410.00
THRU	**TOTAL**		**25,290.0**	**0.0**	**0.0**	**25,290.0**	**4.636**	**4.636**	**1,172,410.00**
Dec-17									

TAMPA ELECTRIC COMPANY
ENERGY PAYMENT TO QUALIFYING FACILITIES **SCHEDULE E8**
ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

(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-17	VARIOUS	CO-GEN. AS AVAIL.	7,540.0	0.0	0.0	7,540.0	3.524	3.524	265,740.00
	TOTAL		**7,540.0**	**0.0**	**0.0**	**7,540.0**	**3.524**	**3.524**	**265,740.00**
Feb-17	VARIOUS	CO-GEN. AS AVAIL.	7,440.0	0.0	0.0	7,440.0	2.961	2.961	220,310.00
	TOTAL		**7,440.0**	**0.0**	**0.0**	**7,440.0**	**2.961**	**2.961**	**220,310.00**
Mar-17	VARIOUS	CO-GEN. AS AVAIL.	7,550.0	0.0	0.0	7,550.0	2.387	2.387	180,240.00
	TOTAL		**7,550.0**	**0.0**	**0.0**	**7,550.0**	**2.387**	**2.387**	**180,240.00**
Apr-17	VARIOUS	CO-GEN. AS AVAIL.	7,510.0	0.0	0.0	7,510.0	2.013	2.013	151,140.00
	TOTAL		**7,510.0**	**0.0**	**0.0**	**7,510.0**	**2.013**	**2.013**	**151,140.00**
May-17	VARIOUS	CO-GEN. AS AVAIL.	7,510.0	0.0	0.0	7,510.0	2.609	2.609	195,940.00
	TOTAL		**7,510.0**	**0.0**	**0.0**	**7,510.0**	**2.609**	**2.609**	**195,940.00**
Jun-17	VARIOUS	CO-GEN. AS AVAIL.	7,550.0	0.0	0.0	7,550.0	2.338	2.338	176,490.00
	TOTAL		**7,550.0**	**0.0**	**0.0**	**7,550.0**	**2.338**	**2.338**	**176,490.00**
Jul-17	VARIOUS	CO-GEN. AS AVAIL.	7,460.0	0.0	0.0	7,460.0	2.825	2.825	210,770.00
	TOTAL		**7,460.0**	**0.0**	**0.0**	**7,460.0**	**2.825**	**2.825**	**210,770.00**
Aug-17	VARIOUS	CO-GEN. AS AVAIL.	7,550.0	0.0	0.0	7,550.0	3.303	3.303	249,340.00
	TOTAL		**7,550.0**	**0.0**	**0.0**	**7,550.0**	**3.303**	**3.303**	**249,340.00**
Sep-17	VARIOUS	CO-GEN. AS AVAIL.	7,510.0	0.0	0.0	7,510.0	2.287	2.287	171,790.00
	TOTAL		**7,510.0**	**0.0**	**0.0**	**7,510.0**	**2.287**	**2.287**	**171,790.00**
Oct-17	VARIOUS	CO-GEN. AS AVAIL.	7,520.0	0.0	0.0	7,520.0	3.058	3.058	229,930.00
	TOTAL		**7,520.0**	**0.0**	**0.0**	**7,520.0**	**3.058**	**3.058**	**229,930.00**
Nov-17	VARIOUS	CO-GEN. AS AVAIL.	7,600.0	0.0	0.0	7,600.0	2.866	2.866	217,840.00
	TOTAL		**7,600.0**	**0.0**	**0.0**	**7,600.0**	**2.866**	**2.866**	**217,840.00**
Dec-17	VARIOUS	CO-GEN. AS AVAIL.	7,370.0	0.0	0.0	7,370.0	2.438	2.438	179,650.00
	TOTAL		**7,370.0**	**0.0**	**0.0**	**7,370.0**	**2.438**	**2.438**	**179,650.00**
TOTAL Jan-17 THRU Dec-17	VARIOUS	CO-GEN. AS AVAIL.	90,110.0	0.0	0.0	90,110.0	2.718	2.718	2,449,180.00
	TOTAL		**90,110.0**	**0.0**	**0.0**	**90,110.0**	**2.718**	**2.718**	**2,449,180.00**

TAMPA ELECTRIC COMPANY
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD: JANUARY 2017 THROUGH DECEMBER 2017

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) ($000)	FUEL SAVINGS (9B)-(8)
Jan-17	VARIOUS	ECONOMY	23,840.0	0.0	23,840.0	3.133	746,840.00	3.133	746,840.00	0.00
Feb-17	VARIOUS	ECONOMY	26,580.0	0.0	26,580.0	3.120	829,340.00	3.120	829,340.00	0.00
Mar-17	VARIOUS	ECONOMY	23,540.0	0.0	23,540.0	3.186	749,990.00	3.186	749,990.00	0.00
Apr-17	VARIOUS	ECONOMY	26,550.0	0.0	26,550.0	3.250	862,750.00	3.257	864,750.00	2,000.00
May-17	VARIOUS	ECONOMY	24,120.0	0.0	24,120.0	2.966	715,430.00	2.966	715,430.00	0.00
Jun-17	VARIOUS	ECONOMY	29,580.0	0.0	29,580.0	3.816	1,128,900.00	4.005	1,184,790.00	55,890.00
Jul-17	VARIOUS	ECONOMY	23,900.0	0.0	23,900.0	3.062	731,910.00	3.405	813,680.00	81,770.00
Aug-17	VARIOUS	ECONOMY	26,930.0	0.0	26,930.0	3.286	884,800.00	3.737	1,006,350.00	121,550.00
Sep-17	VARIOUS	ECONOMY	24,450.0	0.0	24,450.0	3.232	790,190.00	3.232	790,190.00	0.00
Oct-17	VARIOUS	ECONOMY	27,920.0	0.0	27,920.0	4.302	1,201,060.00	4.875	1,361,210.00	160,150.00
Nov-17	VARIOUS	ECONOMY	26,630.0	0.0	26,630.0	3.095	824,330.00	3.443	916,840.00	92,510.00
Dec-17	VARIOUS	ECONOMY	22,860.0	0.0	22,860.0	3.048	696,680.00	3.206	732,870.00	36,190.00
TOTAL	VARIOUS	ECONOMY	**306,900.0**	**0.0**	**306,900.0**	**3.311**	**10,162,220.00**	**3.490**	**10,712,280.00**	**550,060.00**

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SCHEDULE E10

TAMPA ELECTRIC COMPANY
RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1,000 KWH

	Current Jan 16 - Dec 16	Projected Jan 17 - Dec 17	Difference $	Difference %
Base Rate Revenue *	61.94	68.62	6.68	10.8%
Fuel Recovery Revenue	33.61	26.42	(7.19)	-21.4%
Conservation Revenue	1.91	2.25	0.34	17.8%
Capacity Revenue	1.78	0.88	(0.90)	-50.6%
Environmental Revenue	4.32	3.89	(0.43)	-10.0%
Florida Gross Receipts Tax Revenue	2.66	2.62	(0.04)	-1.5%
TOTAL REVENUE	**$106.22**	**$104.68**	**($1.54)**	**-1.4%**

*** Base rate change effective January 1, 2017.**

DOCKET NO. 160001-EI
EXHIBIT NO. PAR-3
DOCUMENT NO. 2, PAGE 29 OF 30

SCHEDULE H1

TAMPA ELECTRIC COMPANY
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
PERIOD: JANUARY THROUGH DECEMBER

		ACTUAL 2014	ACTUAL 2015	ACT/EST 2016	EST 2017	DIFFERENCE (%) 2015-2014	2016-2015	2017-2016
FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL {1}	0	0	0	0	0.0%	0.0%	0.0%
2	LIGHT OIL {1}	0	100,149	2,222,900	651,015	0.0%	2119.6%	-70.7%
3	COAL	413,363,010	315,575,618	258,935,180	307,756,318	-23.7%	-17.9%	18.9%
4	NATURAL GAS	307,201,884	331,614,300	290,482,817	355,522,119	7.9%	-12.4%	22.4%
5	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6	OTHER	0	0	0	0	0.0%	0.0%	0.0%
7	**TOTAL ($)**	**720,564,894**	**647,290,067**	**551,640,897**	**663,929,452**	**-10.2%**	**-14.8%**	**20.4%**
SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL {1}	0	0	0	0	0.0%	0.0%	0.0%
9	LIGHT OIL {1}	0	264	1,612	2,900	0.0%	510.6%	79.9%
10	COAL	11,594,881	9,118,709	7,483,309	9,297,050	-21.4%	-17.9%	24.2%
11	NATURAL GAS	7,115,927	9,919,007	10,213,009	10,325,990	39.4%	3.0%	1.1%
12	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
13	OTHER	0	0	3,623	36,390	0.0%	0.0%	904.4%
14	**TOTAL (MWH)**	**18,710,808**	**19,037,980**	**17,701,553**	**19,662,330**	**1.7%**	**-7.0%**	**11.1%**
UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL) {1}	0	0	0	0	0.0%	0.0%	0.0%
16	LIGHT OIL (BBL) {1}	0	777	3,192	5,380	0.0%	310.8%	68.5%
17	COAL (TON)	4,989,298	4,016,804	3,250,542	4,035,520	-19.5%	-19.1%	24.1%
18	NATURAL GAS (MCF)	52,983,025	74,846,827	77,575,520	72,590,650	41.3%	3.6%	-6.4%
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}	0	4,484	18,511	31,360	896700.0%	312.8%	69.4%
23	COAL	120,048,010	96,061,582	78,016,055	96,268,020	-20.0%	-18.8%	23.4%
24	NATURAL GAS	54,096,745	76,630,631	79,344,737	74,342,290	41.7%	3.5%	-6.3%
25	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
26	OTHER	0	0	0	0	0.0%	0.0%	0.0%
27	**TOTAL (MMBTU)**	**174,144,756**	**172,696,697**	**157,379,303**	**170,641,670**	**-0.8%**	**-8.9%**	**8.4%**
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	0.01	0.01	0.0%	0.0%	0.0%
30	COAL	61.97	47.90	42.27	47.28	-22.7%	-11.8%	11.9%
31	NATURAL GAS	38.03	52.10	57.70	52.52	37.0%	10.7%	-9.0%
32	NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
33	OTHER	0.00	0.00	0.02	0.19	0.0%	0.0%	850.0%
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}	0.00	128.89	696.40	121.01	0.0%	440.3%	-82.6%
37	COAL ($/TON)	82.85	78.56	79.66	76.26	-5.2%	1.4%	-4.3%
38	NATURAL GAS ($/MCF)	5.80	4.43	3.74	4.90	-23.6%	-15.6%	31.0%
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}	0.00	22.33	120.09	20.76	0.0%	437.8%	-82.7%
43	COAL	3.44	3.29	3.32	3.20	-4.4%	0.9%	-3.6%
44	NATURAL GAS	5.68	4.33	3.66	4.78	-23.8%	-15.5%	30.6%
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)**	**4.14**	**3.75**	**3.51**	**3.89**	**-9.4%**	**-6.4%**	**10.8%**
BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL {1}	0	0	0	0	0.0%	0.0%	0.0%
49	LIGHT OIL {1}	0	16,985	11,483	10,814	0.0%	-32.4%	-5.8%
50	COAL	10,354	10,535	10,425	10,355	1.7%	-1.0%	-0.7%
51	NATURAL GAS	7,602	7,726	7,769	7,200	1.6%	0.6%	-7.3%
52	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
53	OTHER	0	0	0	0	0.0%	0.0%	0.0%
54	**TOTAL (BTU/KWH)**	**9,307**	**9,071**	**8,891**	**8,679**	**-2.5%**	**-2.0%**	**-2.4%**
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}	0.00	37.94	137.90	22.45	0.0%	263.5%	-83.7%
57	COAL	3.57	3.46	3.46	3.31	-3.1%	0.0%	-4.3%
58	NATURAL GAS	4.32	3.34	2.84	3.44	-22.7%	-15.0%	21.1%
59	NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
60	OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61	**TOTAL (cents/KWH)**	**3.85**	**3.40**	**3.12**	**3.38**	**-11.7%**	**-8.2%**	**8.3%**

{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 2017 - DECEMBER 2017

Tampa Electric Company
Comparison of Levelized and Tiered Fuel Revenues
For the Period Janury 2017 through December 2017

	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	6,081,137	2.956	179,758,406	2.642	160,663,636
TIER II (Over 1,000) kWh	2,783,494	2.956	82,280,087	3.642	101,374,857
Total	8,864,631		262,038,493		262,038,493

EXHIBIT TO THE TESTIMONY OF

PENELOPE A. RUSK

DOCUMENT NO. 4

CAPITAL PROJECTS APPROVED FOR

FUEL CLAUSE RECOVERY

JANUARY 2017 - DECEMBER 2017

POLK 1 IGNITION CONVERSION
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2017 THROUGH DECEMBER 2017

		PROJECTED JANUARY	PROJECTED FEBRUARY	PROJECTED MARCH	PROJECTED APRIL	PROJECTED MAY	PROJECTED JUNE	PROJECTED JULY	PROJECTED AUGUST	PROJECTED SEPTEMBER	PROJECTED OCTOBER	PROJECTED NOVEMBER	PROJECTED 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	$ 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	$ 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	$ 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%	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	269,225	269,225	269,225	269,225	269,225	269,225	3,230,701
10	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
11	BEGINNING BALANCE DEPRECIATION	11,297,899	11,567,125	11,836,350	12,105,575	12,374,800	12,644,025	12,913,250	13,182,475	13,451,700	13,720,925	13,990,150	14,259,375	11,297,899
12	ENDING BALANCE DEPRECIATION	11,567,125	11,836,350	12,105,575	12,374,800	12,644,025	12,913,250	13,182,475	13,451,700	13,720,925	13,990,150	14,259,375	14,528,600	14,528,600
13														
14														
15	ENDING NET INVESTMENT	4,576,826	4,307,601	4,038,376	3,769,151	3,499,926	3,230,701	2,961,476	2,692,251	2,423,026	2,153,801	1,884,575	1,615,350	1,615,350
16														
17														
18	AVERAGE INVESTMENT	$ 4,711,439	$ 4,442,214	$ 4,172,989	$ 3,903,763	$ 3,634,538	$ 3,365,313	$ 3,096,088	$ 2,826,863	$ 2,557,638	$ 2,288,413	$ 2,019,188	$ 1,749,963	
19	ALLOWED EQUITY RETURN	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	
20	EQUITY COMPONENT AFTER-TAX	16,904	15,938	14,972	14,006	13,040	12,074	11,108	10,142	9,176	8,210	7,245	6,279	139,094
21	CONVERSION TO PRE-TAX	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	
22	EQUITY COMPONENT PRE-TAX	27,591	26,014	24,437	22,861	21,284	19,707	18,130	16,554	14,977	13,400	11,825	10,249	227,029
23														
24	ALLOWED DEBT RETURN	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	
25	DEBT COMPONENT	7,439	7,014	6,588	6,163	5,738	5,313	4,888	4,463	4,038	3,613	3,188	2,763	61,208
26														
27	TOTAL RETURN REQUIREMENTS	35,030	33,028	31,025	29,024	27,022	25,020	23,018	21,017	19,015	17,013	15,013	13,012	288,237
28														
29	TOTAL DEPRECIATION & RETURN	304,255	302,253	300,250	298,249	296,247	294,245	292,243	290,242	288,240	286,238	284,238	282,237	3,518,938
30														
31	ESTIMATED FUEL SAVINGS	$0	$0	$615,963	$642,950	$0	$653,800	$0	$623,760	$0	$1,048,705	$659,050	$0	$4,244,228
32	TOTAL DEPRECIATION & RETURN	$304,255	$302,253	$300,250	$298,249	$296,247	$294,245	$292,243	$290,242	$288,240	$286,238	$284,238	$282,237	$3,518,938
33	NET BENEFIT (COST) TO RATEPAYER	($304,255)	($302,253)	$315,713	$344,701	($296,247)	$359,555	($292,243)	$333,518	($288,240)	$762,467	$374,812	($282,237)	$725,290
34														

35 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
36 RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 8.9219% (EQUITY 7.0273% , DEBT 1.8946%). RATES ARE BASED ON THE MAY SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
36 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 38.575%
37 ZERO PROJECTED GENERATION RESULTS IN ZERO ESTIMATED FUEL SAVINGS FOR THAT MONTH.

BIG BEND UNITS 1-4 IGNITERS CONVERSION TO NATURAL GAS
SCHEDULE OF DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2017 THROUGH DECEMBER 2017

		PROJECTED JANUARY	PROJECTED FEBRUARY	PROJECTED MARCH	PROJECTED APRIL	PROJECTED MAY	PROJECTED JUNE	PROJECTED JULY	PROJECTED AUGUST	PROJECTED SEPTEMBER	PROJECTED OCTOBER	PROJECTED NOVEMBER	PROJECTED 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	-	-	-	-	-	-	-	-	-	-	-	-	-
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	6,731,641	7,080,147	7,428,652	7,777,158	8,125,664	8,474,170	8,822,676	9,171,181	9,519,687	9,868,193	10,216,699	10,565,205	6,731,641
12	ENDING BALANCE DEPRECIATION	7,080,147	7,428,652	7,777,158	8,125,664	8,474,170	8,822,676	9,171,181	9,519,687	9,868,193	10,216,699	10,565,205	10,913,710	10,913,710
13														
14														
15	ENDING NET INVESTMENT	13,830,202	13,481,696	13,133,190	12,784,684	12,436,178	12,087,673	11,739,167	11,390,661	11,042,155	10,693,649	10,345,144	9,996,638	9,996,638
16														
17														
18	AVERAGE INVESTMENT	$14,004,454	$13,655,949	$13,307,443	$12,958,937	$12,610,431	$12,261,925	$11,913,420	$11,564,914	$11,216,408	$10,867,902	$10,519,396	$10,170,891	
19	ALLOWED EQUITY RETURN	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	.35878%	
20	EQUITY COMPONENT AFTER-TAX	50,246	48,995	47,745	46,495	45,244	43,994	42,743	41,493	40,243	38,992	37,742	36,491	520,423
21	CONVERSION TO PRE-TAX	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	1.63220	
22	EQUITY COMPONENT PRE-TAX	$82,012	$79,970	$77,929	$75,889	$73,847	$71,807	$69,765	$67,725	$65,685	$63,643	$61,602	$59,561	$849,435
23														
24	ALLOWED DEBT RETURN	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	.15788%	
25	DEBT COMPONENT	$22,111	$21,560	$21,010	$20,460	$19,910	$19,360	$18,809	$18,259	$17,709	$17,159	$16,608	$16,058	$229,013
26														
27	TOTAL RETURN REQUIREMENTS	$104,123	$101,530	$98,939	$96,349	$93,757	$91,167	$88,574	$85,984	$83,394	$80,802	$78,210	$75,619	$1,078,448
28	PRIOR MONTH TRUE-UP													-
29	TOTAL DEPRECIATION & RETURN	$452,629	$450,036	$447,445	$444,855	$442,263	$439,673	$437,080	$434,490	$431,900	$429,308	$426,716	$424,125	$5,260,518
30														
31	ESTIMATED FUEL SAVINGS	$497,845	$571,799	$561,492	$486,476	$165,337	$582,026	$651,776	$508,041	$490,298	$411,939	$739,450	$391,706	$6,058,183
32	TOTAL DEPRECIATION & RETURN	$452,629	$450,036	$447,445	$444,855	$442,263	$439,673	$437,080	$434,490	$431,900	$429,308	$426,716	$424,125	$5,260,518
33	NET BENEFIT (COST) TO RATEPAYER	$45,216	$121,763	$114,047	$41,622	($276,926)	$142,353	$214,696	$73,551	$58,398	($17,369)	$312,735	($32,419)	$797,666

34 DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
35 RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 8.9219% (EQUITY 7.0273% , DEBT 1.8946%). RATES ARE BASED ON THE MAY SURVEILLANCE REPORT PER THE WACC STIPULATION & SETTLEMENT AGREEMENT (JULY 17, 2012).
36 RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 38.575%
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 2017 to December 2017

	(1) Jurisdictional Rate Base Actual May 2016 Capital Structure ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,548,383	35.17%	5.17%	1.82%
Short Term Debt	25,435	0.58%	0.90%	0.01%
Preferred Stock	0	0.00%	0.00%	0.00%
Customer Deposits	106,847	2.43%	2.29%	0.06%
Common Equity	1,847,526	41.96%	10.25%	4.30%
Deferred ITC - Weighted Cost	7,686	0.17%	7.89%	0.01%
Accumulated Deferred Income Taxes & Zero Cost ITCs	866,653	19.69%	0.00%	0.00%
Total	$ 4,402,530	100.00%		6.20%

ITC split between Debt and Equity:

Long Term Debt	$ 1,548,383	Long Term Debt	45.26%
Short Term Debt	25,435	Short Term Debt	0.74%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	1,847,526	Equity - Common	54.00%
Total	$ 3,421,345	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = .0100% * 46.00%	0.0046%
Equity = .0100% * 54.00%	0.0054%
Weighted Cost	0.0100%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.3000%
Deferred ITC - Weighted Cost	0.0054%
	4.3054%
Times Tax Multiplier	1.632200
Total Equity Component	7.0273%

Total Debt Cost Rate:

Long Term Debt	1.8200%
Short Term Debt	0.0100%
Customer Deposits	0.0600%
Deferred ITC - Weighted Cost	0.0046%
Total Debt Component	1.8946%
	8.9219%

Notes:

Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2013 Base Rates Settlement Agreement Dated September 6, 2013.
Column (4) - Column (2) x Column (3)

GENERATING PERFORMANCE INCENTIVE FACTOR

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DOCUMENT NO.	TITLE	BATES STAMPED PAGE NO.
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2	Actual Unit Performance Data	43

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 52
PARTY: TAMPA ELECTRIC COMPANY – (DIRECT)
DESCRIPTION: Brian S. Buckley BSB-1

EXHIBIT NO. ___ (BSB-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 160001-EI
GPIF 2015 FINAL TRUE-UP
DOCUMENT NO. 1

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCKET NO. 160001-EI

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2015 – DECEMBER 2015

TRUE-UP

DOCUMENT NO. 1

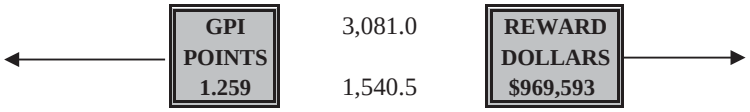
GPIF SCHEDULES

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2015 - DECEMBER 2015
TRUE-UP
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TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE - ACTUAL
JANUARY 2015 - DECEMBER 2015

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	15,405.1	7,702.5
+9	13,864.6	6,932.3
+8	12,324.1	6,162.0
+7	10,783.6	5,391.8
+6	9,243.0	4,621.5
+5	7,702.5	3,851.3
+4	6,162.0	3,081.0
+3	4,621.5	2,310.8
+2	3,081.0	1,540.5
+1	1,540.5	770.3
0	0.0	0.0
-1	(1,456.1)	(770.3)
-2	(2,912.1)	(1,540.5)
-3	(4,368.2)	(2,310.8)
-4	(5,824.2)	(3,081.0)
-5	(7,280.3)	(3,851.3)
-6	(8,736.3)	(4,621.5)
-7	(10,192.4)	(5,391.8)
-8	(11,648.4)	(6,162.0)
-9	(13,104.5)	(6,932.3)
-10	(14,560.5)	(7,702.5)



TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS - ACTUAL
JANUARY 2015 - DECEMBER 2015

Line 1	Beginning of period balance of common equity: End of month common equity:		$	2,111,163,916	
Line 2	Month of January	2015	$	2,127,180,507	
Line 3	Month of February	2015	$	2,093,480,086	
Line 4	Month of March	2015	$	2,130,295,700	
Line 5	Month of April	2015	$	2,107,055,892	
Line 6	Month of May	2015	$	2,131,345,778	
Line 7	Month of June	2015	$	2,158,378,567	
Line 8	Month of July	2015	$	2,128,206,619	
Line 9	Month of August	2015	$	2,209,343,431	
Line 10	Month of September	2015	$	2,233,000,848	
Line 11	Month of October	2015	$	2,251,769,894	
Line 12	Month of November	2015	$	2,260,579,571	
Line 13	Month of December	2015	$	2,270,518,569	
Line 14	(Summation of line 1 through line 13 divided by 13)		$	2,170,178,414	
Line 15	25 Basis points			0.0025	
Line 16	Revenue Expansion Factor			61.27%	
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	8,855,413	
Line 18	Jurisdictional Sales			19,005,398	MWH
Line 19	Total Sales			19,005,398	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)		$	8,855,413	
Line 22	Incentive Cap (50% of projected fuel savings at 10 GPIF-Point level from Sheet No. 3.515)		$	7,702,537	
Line 23	**Maximum Allowed GPIF Reward (At 10 GPIF-Point Level; the lesser of line 21 and line 22)**		**$**	**7,702,537**	

TAMPA ELECTRIC COMPANY
CALCULATION OF SYSTEM GPIF POINTS - ACTUAL
JANUARY 2015 - DECEMBER 2015

PLANT / UNIT	12 MONTH ADJ. ACTUAL PERFORMANCE		WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
BIG BEND 1	62.2%	EAF	7.78%	2.288	0.178
BIG BEND 2	46.2%	EAF	2.04%	-10.000	-0.204
BIG BEND 3	70.0%	EAF	1.49%	-10.000	-0.149
BIG BEND 4	78.7%	EAF	4.13%	-2.700	-0.111
POLK 1	70.3%	EAF	0.60%	-10.000	-0.060
BAYSIDE 1	92.6%	EAF	3.39%	10.000	0.339
BAYSIDE 2	90.3%	EAF	10.11%	10.000	1.011
BIG BEND 1	10,784	ANOHR	8.43%	-10.000	-0.843
BIG BEND 2	10,383	ANOHR	11.29%	0.000	0.000
BIG BEND 3	10,190	ANOHR	8.97%	10.000	0.897
BIG BEND 4	10,363	ANOHR	8.86%	0.000	0.000
POLK 1	10,157	ANOHR	16.65%	6.998	1.165
BAYSIDE 1	7,576	ANOHR	6.02%	-10.000	-0.602
BAYSIDE 2	7,529	ANOHR	10.24%	-3.527	-0.361
			100.00%		1.259

GPIF REWARD **$ 969,593**

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2015 - DECEMBER 2015
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 1	7.78%	61.2	65.5	52.6	1,197.9	(284.9)	62.2	274.1
BIG BEND 2	2.04%	75.2	79.2	67.3	314.8	(548.1)	46.2	(548.1)
BIG BEND 3	1.49%	79.2	82.4	72.9	229.3	(572.6)	70.0	(572.6)
BIG BEND 4	4.13%	80.3	83.2	74.4	635.7	(1,103.8)	78.7	(298.1)
POLK 1	0.60%	77.1	79.6	72.0	91.9	(222.1)	70.3	(222.1)
BAYSIDE 1	3.39%	89.9	91.2	87.3	522.4	(908.6)	92.6	522.4
BAYSIDE 2	10.11%	86.6	88.4	83.0	1,556.9	(64.2)	90.3	1,556.9
GPIF SYSTEM	**29.53%**				**4,548.9**	**(3,704.4)**		

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 1	8.43%	10,563	94.8	10,368	10,757	1,299.3	(1,299.3)	10,784	(1,299.3)
BIG BEND 2	11.29%	10,379	92.7	10,149	10,609	1,739.7	(1,739.7)	10,383	0.0
BIG BEND 3	8.97%	10,495	92.5	10,326	10,664	1,382.3	(1,382.3)	10,190	1,382.3
BIG BEND 4	8.86%	10,416	97.6	10,245	10,587	1,365.4	(1,365.4)	10,363	0.0
POLK 1	16.65%	10,552	96.6	10,020	11,085	2,564.5	(2,564.5)	10,157	1,794.6
BAYSIDE 1	6.02%	7,414	52.3	7,322	7,505	928.0	(928.0)	7,576	(928.0)
BAYSIDE 2	10.24%	7,447	51.7	7,351	7,542	1,576.8	(1,576.8)	7,529	(556.2)
GPIF SYSTEM	**70.47%**					**10,856.1**	**(10,856.1)**		

TAMPA ELECTRIC COMPANY
UNIT PERFORMANCE DATA - ACTUAL
JANUARY 2015 - DECEMBER 2015

PLANT / UNIT	ACTUAL EAF (%)	ADJUSTMENTS [1] TO EAF (%)	EAF ADJUSTED ACTUAL (%)
BIG BEND 1	59.0	3.2	62.2
BIG BEND 2	45.8	0.4	46.2
BIG BEND 3	72.2	-2.2	70.0
BIG BEND 4	81.1	-2.4	78.7
POLK 1	70.5	-0.2	70.3
BAYSIDE 1	85.9	6.7	92.6
BAYSIDE 2	89.2	1.1	90.3

PLANT / UNIT	ACTUAL ANOHR (Btu/kwh)	ADJUSTMENTS [2] TO ANOHR (Btu/kwh)	ANOHR ADJUSTED ACTUAL (Btu/kwh)
BIG BEND 1	10,747	37	10,784
BIG BEND 2	10,492	-109	10,383
BIG BEND 3	10,349	-159	10,190
BIG BEND 4	10,377	-14	10,363
POLK 1	10,269	-112	10,157
BAYSIDE 1	7,377	199	7,576
BAYSIDE 2	7,399	130	7,529

(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. 1
JANUARY 2015 - DECEMBER 2015

WEIGHTING FACTOR = 7.78%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	61.2	59.0	62.2
POH	2,016.0	2,363.7	2,016.0
FOH + EFOH	1,240.3	1,136.7	1,198.5
MOH + EMOH	141.3	90.2	95.1
POF	23.0	27.0	23.0
EFOF	14.2	13.0	13.7
EMOF	1.6	1.0	1.1

2.3 EQUIVALENT AVAILABILITY POINTS

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 2016}{8760 - 2363.7} \times (1136.7 + 90.2) = 1{,}293.6$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 23 - \frac{1293.6}{8760.0} \times 100 = 62.2$$

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. 2
JANUARY 2015 - DECEMBER 2015

WEIGHTING FACTOR = 2.04%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	75.2	45.8	46.2
POH	576.0	654.1	576.0
FOH + EFOH	1,230.8	3,942.5	3,980.5
MOH + EMOH	365.2	154.9	156.4
POF	6.6	7.5	6.6
EFOF	14.0	45.0	45.4
EMOF	4.2	1.8	1.8

-10.000 **EQUIVALENT AVAILABILITY POINTS**

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 576}{8760 - 654.1} \times (3942.5 + 154.9) = 4{,}136.9$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 6.6 - \frac{4136.9}{8760.0} \times 100 = 46.2$$

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 2015 - DECEMBER 2015

WEIGHTING FACTOR = 1.49%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	79.2	72.2	70.0
POH	576.0	328.0	576.0
FOH + EFOH	955.1	1,858.3	1,803.6
MOH + EMOH	288.0	251.8	244.4
POF	6.6	3.7	6.6
EFOF	10.9	21.2	20.6
EMOF	3.3	2.9	2.8

-10.000 **EQUIVALENT AVAILABILITY POINTS**

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 576}{8760 - 328} \times (1858.3 + 251.8) = 2{,}048.0$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 6.6 - \frac{2048.0}{8760.0} \times 100 = 70.0$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 4
JANUARY 2015 - DECEMBER 2015

WEIGHTING FACTOR = 4.13%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	80.3	81.1	78.7
POH	576.0	334.1	576.0
FOH + EFOH	846.9	1,208.2	1,173.5
MOH + EMOH	303.3	114.1	110.8
POF	6.6	3.8	6.6
EFOF	9.7	13.8	13.4
EMOF	3.5	1.3	1.3
	-2.700	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 576}{8760 - 334.1} \times (1208.2 + 114.1) = 1,284.3$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 6.6 - \frac{1284.3}{8760.0} \times 100 = 78.7$$

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
POLK UNIT NO. 1
JANUARY 2015 - DECEMBER 2015

WEIGHTING FACTOR = 0.60%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	77.1	70.5	70.3
POH	1,200.0	1,178.4	1,200.0
FOH + EFOH	619.0	1,278.0	1,274.4
MOH + EMOH	188.1	124.1	123.7
POF	13.7	13.5	13.7
EFOF	7.1	14.6	14.5
EMOF	2.1	1.4	1.4

-10.000 **EQUIVALENT AVAILABILITY POINTS**

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 1200}{8760 - 1178.4} \times (1278 + 124.1) = 1{,}398.1$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 13.7 - \frac{1398.1}{8760.0} \times 100 = 70.3$$

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 2015 - DECEMBER 2015

WEIGHTING FACTOR = 3.39%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	89.9	85.9	92.6
POH	432.0	1,032.8	432.0
FOH + EFOH	84.3	111.7	120.4
MOH + EMOH	371.8	88.4	95.3
POF	4.9	11.8	4.9
EFOF	1.0	1.3	1.4
EMOF	4.2	1.0	1.1
	10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 432}{8760 - 1032.8} \times (111.7 + 88.4) = 215.7$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 4.9 - \frac{215.7}{8760.0} \times 100 = 92.6$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BAYSIDE UNIT NO. 2
JANUARY 2015 - DECEMBER 2015

WEIGHTING FACTOR = 10.11%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	86.6	89.2	90.3
POH	528.0	627.1	528.0
FOH + EFOH	291.3	182.2	184.4
MOH + EMOH	355.2	139.1	140.8
POF	6.0	7.2	6.0
EFOF	3.3	2.1	2.1
EMOF	4.1	1.6	1.6
	10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 528}{8760 - 627.1} \times (182.2 + 139.1) = 325.2$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 6 - \frac{325.2}{8760.0} \times 100 = 90.3$$

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. 1
JANUARY 2015 - DECEMBER 2015

WEIGHTING FACTOR = 8.43%

	12 MONTH TARGET	**12 MONTH ACTUAL PERFORMANCE**
ANOHR (Btu/kwh)	10,563	10,747
NET GENERATION (GWH)	2,171.6	1,808.3
OPERATING BTU (10^9)	21,861.6	19,434.3
NET OUTPUT FACTOR	94.8	78.6

-10.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(2.32) + 10342.99 = ANOHR

78.6 * (2.32) + 10342.99 = 10,525

10,747 - 10,525 = 222

10,563 + 222 = 10,784 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OUTPUT FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 2
JANUARY 2015 - DECEMBER 2015

WEIGHTING FACTOR = 11.29%

	12 MONTH TARGET	**12 MONTH ACTUAL PERFORMANCE**
ANOHR (Btu/kwh)	10,379	10,492
NET GENERATION (GWH)	2,625.7	1,325.4
OPERATING BTU (10^9)	26,848.1	13,906.0
NET OUTPUT FACTOR	92.7	76.1

0.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-6.56) + 10987.1 = ANOHR

76.1 * (-6.56) + 10987.1 = 10,488

10,492 - 10,488 = 4

10,379 + 4 = 10,383 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OUTPUT FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 3
JANUARY 2015 - DECEMBER 2015

WEIGHTING FACTOR = 8.97%

	12 MONTH TARGET	**12 MONTH ACTUAL PERFORMANCE**
ANOHR (Btu/kwh)	10,495	10,349
NET GENERATION (GWH)	2,696.6	2,223.2
OPERATING BTU (10^9)	28,011.4	23,008.6
NET OUTPUT FACTOR	92.5	84.6

10.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-20.12) + 12356.06 = ANOHR

84.6 * (-20.12) + 12356.06 = 10,654

10,349 - 10,654 = -305

10,495 + -305 = 10,190 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OUTPUT FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 4
JANUARY 2015 - DECEMBER 2015

WEIGHTING FACTOR = 8.86%

	12 MONTH TARGET	**12 MONTH ACTUAL PERFORMANCE**
ANOHR (Btu/kwh)	10,416	10,377
NET GENERATION (GWH)	2,932.9	2,769.1
OPERATING BTU (10^9)	29,634.4	28,733.9
NET OUTPUT FACTOR	97.6	82.8

0.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-0.94) + 10507.72 = ANOHR

82.8 * (-0.94) + 10507.72 = 10,430

10,377 - 10,430 = -53

10,416 + -53 = 10,363 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OUTPUT FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
POLK UNIT NO. 1
JANUARY 2015 - DECEMBER 2015

WEIGHTING FACTOR = 16.65%

	12 MONTH TARGET	**12 MONTH ACTUAL PERFORMANCE**
ANOHR (Btu/kwh)	10,552	10,269
NET GENERATION (GWH)	1,410.2	1,237.4
OPERATING BTU (10^9)	14,278.0	12,707.2
NET OUTPUT FACTOR	96.6	94.2

6.998 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-47.27) + 15116.96 = ANOHR

94.2 * (-47.27) + 15116.96 = 10,664

10,269 - 10,664 = -395

10,552 + -395 = 10,157 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OUTPUT FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BAYSIDE UNIT NO. 1
JANUARY 2015 - DECEMBER 2015

WEIGHTING FACTOR = 6.02%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	7,414	7,377
NET GENERATION (GWH)	2,619.6	3,649.3
OPERATING BTU (10^9)	19,239.4	26,920.7
NET OUTPUT FACTOR	52.3	67.8

-10.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-12.82) + 8084.29 = ANOHR

67.8 * (-12.82) + 8084.29 = 7,215

7,377 - 7,215 = 162

7,414 + 162 = 7,576 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OUTPUT FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BAYSIDE UNIT NO. 2
JANUARY 2015 - DECEMBER 2015

WEIGHTING FACTOR = 10.24%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	7,447	7,399
NET GENERATION (GWH)	3,795.9	5,267.2
OPERATING BTU (10^9)	27,799.2	38,970.9
NET OUTPUT FACTOR	51.7	70.1

-3.527 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF *(-7.05) + 7811.35 = ANOHR

70.1 * (-7.05) + 7811.35 = 7,317

7,399 - 7,317 = 82

7,447 + 82 = 7,529 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

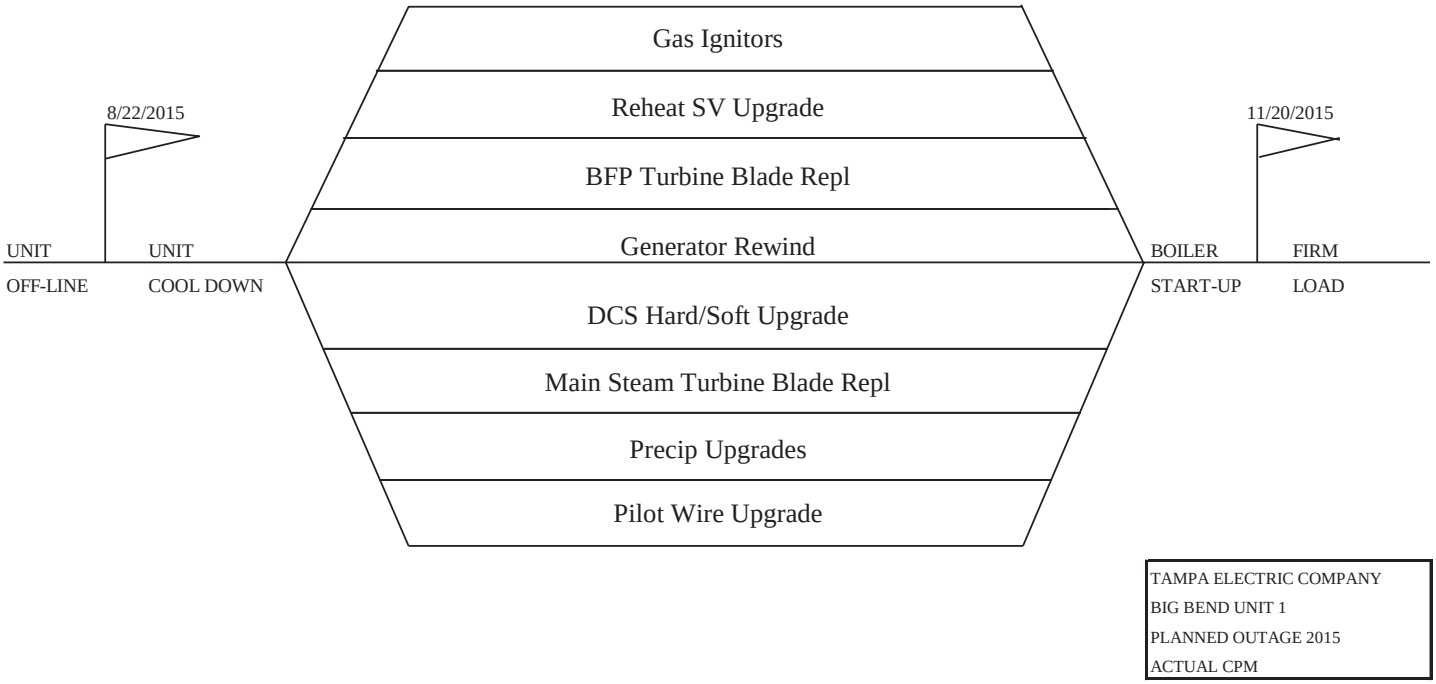
ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OUTPUT FACTOR

TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ACTUAL)
GPIF UNITS
JANUARY 2015 - DECEMBER 2015

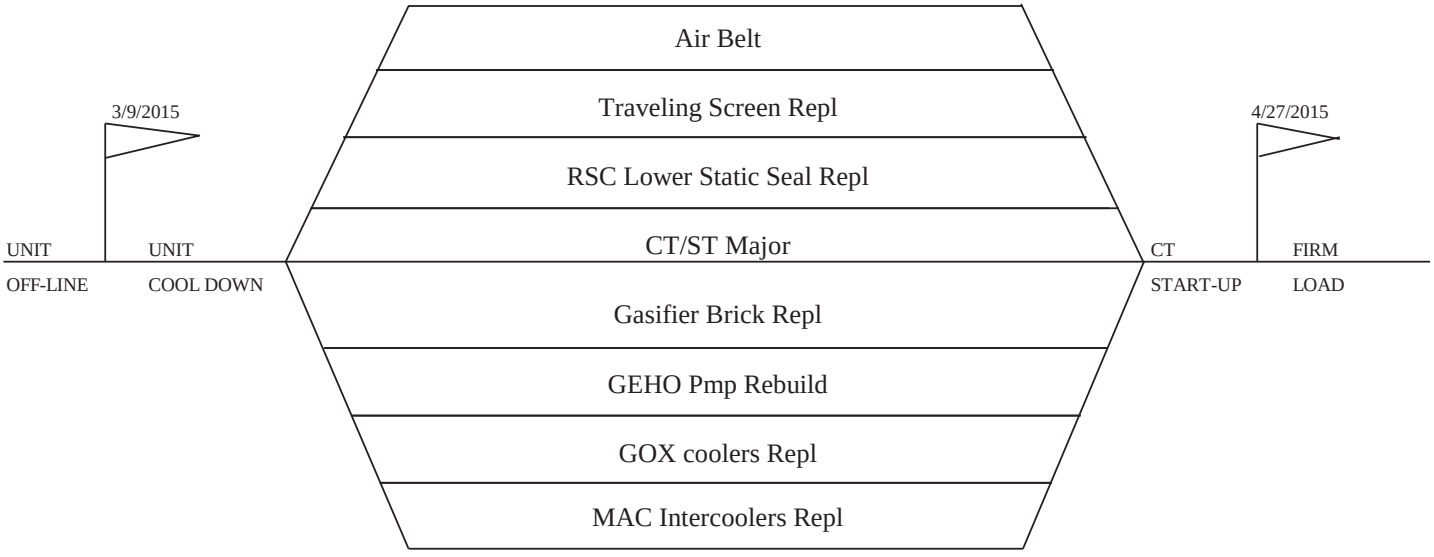
	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
+	BIG BEND 1	Jan 21	-	Jan 30	Fuel System Cleanup and FGD/SCR work
		Aug 22	-	Nov 20	Reheat SV Upgrade, BFP Turbine Blade Repl, DCS Hard/Soft Upgrade, Generator Rewind, Main Steam Turbine Blade Replac, Precip Upgrades, Pilot Wire Upgrade, Gas Ignitors
	BIG BEND 2	Jan 21	-	Jan 31	Fuel System Cleanup and FGD/SCR work
		May 26	-	Jun 12	Fuel System Cleanup and FGD/SCR work
	BIG BEND 3	Jan 05	-	Jan 18	Fuel System Cleanup and FGD/SCR work
	BIG BEND 4	May 01	-	May 15	Fuel System Cleanup and FGD/SCR work
+	POLK 1	Mar 09	-	Apr 27	CT/ST Major, Traveling Screen Repl, Gasifier Brick Repl, RSC Lower Static Seal Repl, Air Belt, GEHO Pmp Rebuild, GOX coolers repl, MAC Intercoolers Repl
+	BAYSIDE 1	Apr 12	-	Apr 24	Fuel System Cleanup
		Oct 23	-	Nov 22	Steam Turbine Intercept, Hot Reheat, Governor and Throttle valve maintenance. 1A, 1B, 1C Blowdown Tank replacment, HP to CRH attemperation system and valve, 1B Circ pump and motor
	BAYSIDE 2	Feb 22	-	Mar 08	Fuel System Cleanup
		Dec 01	-	Dec 13	Fuel System Cleanup

+ 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 2015 - DECEMBER 2015

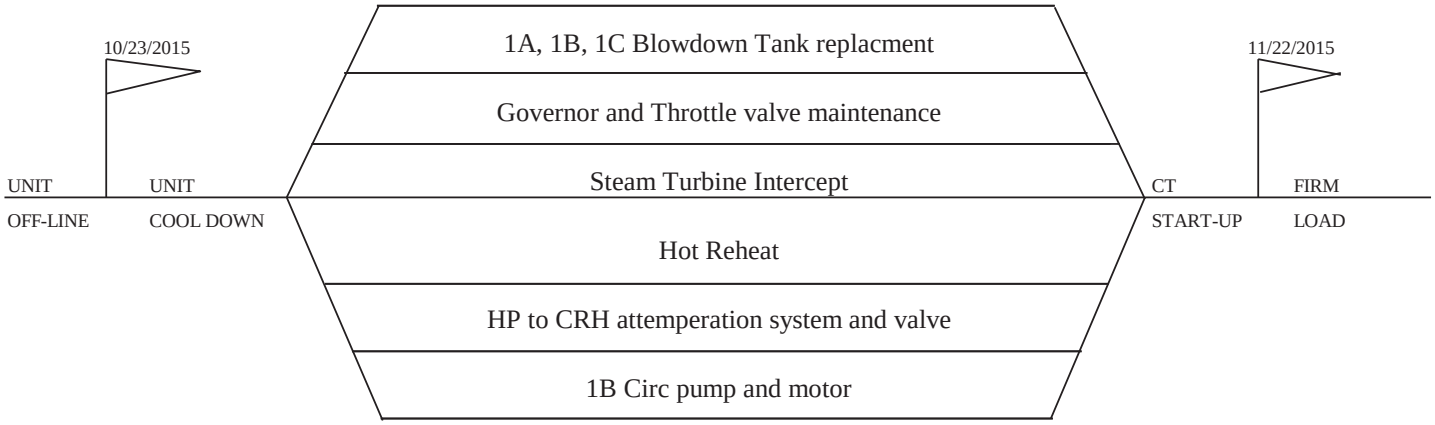


TAMPA ELECTRIC COMPANY
BIG BEND UNIT 1
PLANNED OUTAGE 2015
ACTUAL CPM



TAMPA ELECTRIC COMPANY
POLK UNIT 1
PLANNED OUTAGE 2015
ACTUAL CPM

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2015 - DECEMBER 2015



TAMPA ELECTRIC COMPANY
BAYSIDE UNIT 1
PLANNED OUTAGE 2015
ACTUAL CPM

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2015 - DECEMBER 2015

BIG BEND 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	1,197.9	65.5	+10	1,299.3	10,368
+9	1,078.1	65.1	+9	1,169.4	10,380
+8	958.3	64.7	+8	1,039.5	10,392
+7	838.6	64.2	+7	909.5	10,404
+6	718.8	63.8	+6	779.6	10,416
+5	599.0	63.4	+5	649.7	10,428
+4	479.2	62.9	+4	519.7	10,440
+3	359.4	62.5	+3	389.8	10,452
+2	239.6	62.1	+2	259.9	10,464
+1	119.8	61.6	+1	129.9	10,476
					10,488
0	0.0	61.2	0	0.0	10,563
					10,638
-1	(28.5)	60.4	-1	(129.9)	10,649
-2	(57.0)	59.5	-2	(259.9)	10,661
-3	(85.5)	58.6	-3	(389.8)	10,673
-4	(114.0)	57.8	-4	(519.7)	10,685
-5	(142.4)	56.9	-5	(649.7)	10,697
-6	(170.9)	56.0	-6	(779.6)	10,709
-7	(199.4)	55.2	-7	(909.5)	10,721
-8	(227.9)	54.3	-8	(1,039.5)	10,733
-9	(256.4)	53.5	-9	(1,169.4)	10,745
-10	(284.9)	52.6	-10	(1,299.3)	10,757

EAF POINTS 2.288 → **Adjusted EAF 62.2**

AHR POINTS -10.000 → **Adjusted ANOHR 10,784**

Weighting Factor = 7.78%

Weighting Factor = 8.43%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2015 - DECEMBER 2015

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	314.8	79.2	+10	1,739.7	10,149
+9	283.3	78.8	+9	1,565.7	10,165
+8	251.8	78.4	+8	1,391.8	10,180
+7	220.3	78.0	+7	1,217.8	10,195
+6	188.9	77.6	+6	1,043.8	10,211
+5	157.4	77.2	+5	869.9	10,226
+4	125.9	76.8	+4	695.9	10,242
+3	94.4	76.4	+3	521.9	10,257
+2	63.0	76.0	+2	347.9	10,273
+1	31.5	75.6	+1	174.0	10,288
					10,304
0	0.0	75.2	0 ← **AHR POINTS 0.000**	0.0	**Adjusted ANOHR 10,383** → 10,379
					10,454
-1	(54.8)	74.4	-1	(174.0)	10,469
-2	(109.6)	73.6	-2	(347.9)	10,485
-3	(164.4)	72.8	-3	(521.9)	10,500
-4	(219.2)	72.0	-4	(695.9)	10,516
-5	(274.0)	71.2	-5	(869.9)	10,531
-6	(328.9)	70.4	-6	(1,043.8)	10,547
-7	(383.7)	69.6	-7	(1,217.8)	10,562
-8	(438.5)	68.8	-8	(1,391.8)	10,578
-9	(493.3)	68.1	-9	(1,565.7)	10,593
-10 ← **EAF POINTS -10.000**	(548.1)	**Adjusted EAF 46.2** → 67.3	-10	(1,739.7)	10,609

Weighting Factor = 2.04%

Weighting Factor = 11.29%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2015 - DECEMBER 2015

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	229.3	82.4	+10	1,382.3	10,326
+9	206.4	82.1	+9	1,244.1	10,336
+8	183.5	81.8	+8	1,105.9	10,345
+7	160.5	81.5	+7	967.6	10,355
+6	137.6	81.1	+6	829.4	10,364
+5	114.7	80.8	+5	691.2	10,373
+4	91.7	80.5	+4	552.9	10,383
+3	68.8	80.2	+3	414.7	10,392
+2	45.9	79.9	+2	276.5	10,402
+1	22.9	79.6	+1	138.2	10,411
					10,420
0	0.0	79.2	0	0.0	10,495
					10,570
-1	(57.3)	78.6	-1	(138.2)	10,580
-2	(114.5)	78.0	-2	(276.5)	10,589
-3	(171.8)	77.3	-3	(414.7)	10,599
-4	(229.1)	76.7	-4	(552.9)	10,608
-5	(286.3)	76.1	-5	(691.2)	10,617
-6	(343.6)	75.4	-6	(829.4)	10,627
-7	(400.8)	74.8	-7	(967.6)	10,636
-8	(458.1)	74.2	-8	(1,105.9)	10,646
-9	(515.4)	73.5	-9	(1,244.1)	10,655
-10	(572.6)	72.9	-10	(1,382.3)	10,664

AHR POINTS 10.000

Adjusted ANOHR 10,190

EAF POINTS -10.000

Adjusted EAF 70.0

Weighting Factor = 1.49%

Weighting Factor = 8.97%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2015 - DECEMBER 2015

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	635.7	83.2	+10	1,365.4	10,245
+9	572.1	83.0	+9	1,228.9	10,254
+8	508.5	82.7	+8	1,092.3	10,264
+7	445.0	82.4	+7	955.8	10,274
+6	381.4	82.1	+6	819.2	10,283
+5	317.8	81.8	+5	682.7	10,293
+4	254.3	81.5	+4	546.2	10,302
+3	190.7	81.2	+3	409.6	10,312
+2	127.1	80.9	+2	273.1	10,322
+1	63.6	80.6	+1	136.5	10,331
					10,341
0	0.0	80.3	0	0.0	10,416
					10,491
-1	(110.4)	79.7	-1	(136.5)	10,501
-2	(220.8)	79.1	-2	(273.1)	10,510
-3	(331.1)	78.5	-3	(409.6)	10,520
-4	(441.5)	77.9	-4	(546.2)	10,529
-5	(551.9)	77.3	-5	(682.7)	10,539
-6	(662.3)	76.8	-6	(819.2)	10,549
-7	(772.7)	76.2	-7	(955.8)	10,558
-8	(883.0)	75.6	-8	(1,092.3)	10,568
-9	(993.4)	75.0	-9	(1,228.9)	10,578
-10	(1,103.8)	74.4	-10	(1,365.4)	10,587

EAF POINTS -2.700

Adjusted EAF 78.7

AHR POINTS 0.000

Adjusted ANOHR 10,363

Weighting Factor = 4.13%

Weighting Factor = 8.86%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2015 - DECEMBER 2015

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	91.9	79.6	+10	2,564.5	10,020
+9	82.7	79.4	+9	2,308.1	10,065
+8	73.5	79.1	+8	2,051.6	10,111
+7	64.3	78.9	+7	1,795.2	10,157
+6	55.1	78.6	+6	1,538.7	10,203
+5	45.9	78.4	+5	1,282.3	10,248
+4	36.7	78.1	+4	1,025.8	10,294
+3	27.6	77.8	+3	769.4	10,340
+2	18.4	77.6	+2	512.9	10,386
+1	9.2	77.3	+1	256.5	10,431
					10,477
0	0.0	77.1	0	0.0	10,552
					10,627
-1	(22.2)	76.6	-1	(256.5)	10,673
-2	(44.4)	76.1	-2	(512.9)	10,719
-3	(66.6)	75.6	-3	(769.4)	10,764
-4	(88.9)	75.1	-4	(1,025.8)	10,810
-5	(111.1)	74.6	-5	(1,282.3)	10,856
-6	(133.3)	74.1	-6	(1,538.7)	10,902
-7	(155.5)	73.5	-7	(1,795.2)	10,947
-8	(177.7)	73.0	-8	(2,051.6)	10,993
-9	(199.9)	72.5	-9	(2,308.1)	11,039
-10	(222.1)	72.0	-10	(2,564.5)	11,085

EAF POINTS -10.000

Adjusted EAF 70.3

AHR POINTS 6.998

Adjusted ANOHR 10,157

Weighting Factor = 0.60%

Weighting Factor = 16.65%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2015 - DECEMBER 2015

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	522.4	91.2	+10	928.0	7,322
+9	470.2	91.0	+9	835.2	7,324
+8	417.9	90.9	+8	742.4	7,326
+7	365.7	90.8	+7	649.6	7,327
+6	313.5	90.6	+6	556.8	7,329
+5	261.2	90.5	+5	464.0	7,331
+4	209.0	90.4	+4	371.2	7,332
+3	156.7	90.2	+3	278.4	7,334
+2	104.5	90.1	+2	185.6	7,336
+1	52.2	90.0	+1	92.8	7,337
					7,339
0	0.0	89.9	0	0.0	7,414
					7,489
-1	(90.9)	89.6	-1	(92.8)	7,491
-2	(181.7)	89.3	-2	(185.6)	7,492
-3	(272.6)	89.1	-3	(278.4)	7,494
-4	(363.4)	88.8	-4	(371.2)	7,496
-5	(454.3)	88.6	-5	(464.0)	7,497
-6	(545.2)	88.3	-6	(556.8)	7,499
-7	(636.0)	88.1	-7	(649.6)	7,501
-8	(726.9)	87.8	-8	(742.4)	7,502
-9	(817.7)	87.5	-9	(835.2)	7,504
-10	(908.6)	87.3	-10	(928.0)	7,505

EAF POINTS 10.000

Adjusted EAF 92.6

AHR POINTS -10.000

Adjusted ANOHR 7,576

Weighting Factor = 3.39%

Weighting Factor = 6.02%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2015 - DECEMBER 2015

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	1,556.9	88.4	+10	1,576.8	7,351
+9	1,401.3	88.2	+9	1,419.1	7,354
+8	1,245.6	88.0	+8	1,261.4	7,356
+7	1,089.9	87.8	+7	1,103.8	7,358
+6	934.2	87.7	+6	946.1	7,360
+5	778.5	87.5	+5	788.4	7,362
+4	622.8	87.3	+4	630.7	7,364
+3	467.1	87.1	+3	473.0	7,366
+2	311.4	86.9	+2	315.4	7,368
+1	155.7	86.8	+1	157.7	7,370
					7,372
0	0.0	86.6	0	0.0	7,447
					7,522
-1	(6.4)	86.2	-1	(157.7)	7,524
-2	(12.8)	85.9	-2	(315.4)	7,526
-3	(19.3)	85.5	-3	(473.0)	7,528
-4	(25.7)	85.2	-4	(630.7)	7,530
-5	(32.1)	84.8	-5	(788.4)	7,532
-6	(38.5)	84.5	-6	(946.1)	7,534
-7	(45.0)	84.1	-7	(1,103.8)	7,536
-8	(51.4)	83.8	-8	(1,261.4)	7,538
-9	(57.8)	83.4	-9	(1,419.1)	7,540
-10	(64.2)	83.0	-10	(1,576.8)	7,542

EAF POINTS 10.000

Adjusted EAF 90.3

AHR POINTS -3.527

Adjusted ANOHR 7,529

Weighting Factor = 10.11%

Weighting Factor = 10.24%

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS ACTUAL PERFORMANCE
JANUARY 2015 - DECEMBER 2015
EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	TARGET WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 15 - DEC 15 POF	TARGET PERIOD JAN 15 - DEC 15 EUOF	TARGET PERIOD JAN 15 - DEC 15 EUOR	ACTUAL PERFORMANCE JAN 15 - DEC 15 POF	ACTUAL PERFORMANCE JAN 15 - DEC 15 EUOF	ACTUAL PERFORMANCE JAN 15 - DEC 15 EUOR
BIG BEND 1	7.78%	26.3%	23.0	15.8	20.5	27.0	14.0	19.2
BIG BEND 2	2.04%	6.9%	6.6	18.2	19.5	7.5	46.8	50.5
BIG BEND 3	1.49%	5.0%	6.6	14.2	15.2	3.7	24.1	25.0
BIG BEND 4	4.13%	14.0%	6.6	13.1	14.1	3.8	15.1	15.7
POLK 1	0.60%	2.0%	13.7	9.2	10.7	13.5	16.0	18.5
BAYSIDE 1	3.39%	11.5%	4.9	5.2	5.5	11.8	2.3	2.6
BAYSIDE 2	10.11%	34.2%	6.0	7.4	7.9	7.2	3.7	3.9
GPIF SYSTEM	**29.5%**	**100.0%**	**10.7**	**11.3**	**13.0**	**12.4**	**12.1**	**14.0**

GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%) **78.1** **75.5**

3 PERIOD AVERAGE POF	3 PERIOD AVERAGE EUOF	3 PERIOD AVERAGE EUOR	3 PERIOD AVERAGE EAF
9.8	**12.5**	**14.0**	**77.7**

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	TARGET WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 15 - DEC 15	ADJUSTED ACTUAL HEAT RATE JAN 15 - DEC 15
BIG BEND 1	8.43%	12.0%	10,563	10,784
BIG BEND 2	11.29%	16.0%	10,379	10,383
BIG BEND 3	8.97%	12.7%	10,495	10,190
BIG BEND 4	8.86%	12.6%	10,416	10,363
POLK 1	16.65%	23.6%	10,552	10,157
BAYSIDE 1	6.02%	8.5%	7,414	7,576
BAYSIDE 2	10.24%	14.5%	7,447	7,529
GPIF SYSTEM	**70.5%**	**100.0%**		

GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh) **9,782** **9,696**

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE POINTS CALCULATION
JANUARY 2015 - DECEMBER 2015

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 =	7.78%	*	(BB 1 EAP)	+	2.04%	*	(BB 2 EAP)	+	1.49%	*	(BB 3 EAP)
+	4.13%	*	(BB 4 EAP)	+	0.60%	*	(PK 1 EAP)	+	3.39%	*	(BAY 1 EAP)
+	10.11%	*	(BAY 2 EAP)	+	8.43%	*	(BB 1 AHRP)	+	11.29%	*	(BB 2 AHRP)
+	8.97%	*	(BB 3 AHRP)	+	8.86%	*	(BB 4 AHRP)	+	16.65%	*	(PK 1 AHRP)
+	6.02%	*	(BAY 1 AHRP)	+	10.24%	*	(BAY 2 AHRP)				

GPIP =	7.78%	*	2.288	+	2.04%	*	-10.000	+	1.49%	*	-10.000
+	4.13%	*	-2.700	+	0.60%	*	-10.000	+	3.39%	*	10.000
+	10.11%	*	10.000	+	8.43%	*	-10.000	+	11.29%	*	0.000
+	8.97%	*	10.000	+	8.86%	*	0.000	+	16.65%	*	6.998
+	6.02%	*	-10.000	+	10.24%	*	-3.527				

GPIP =	0.178	+	-0.204	+	-0.149
+	-0.111	+	-0.060	+	0.339
+	1.011	+	-0.843	+	0.000
+	0.897	+	0.000	+	1.165
+	-0.602	+	-0.361		

GPIP = 1.259 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 = $969,593

EXHIBIT NO. ___ (BSB-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 160001-EI
GPIF 2015 FINAL TRUE-UP
DOCUMENT NO. 2

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCKET NO. 160001-EI

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2015 – DECEMBER 2015

TRUE-UP

DOCUMENT NO. 2

ACTUAL UNIT PERFORMANCE DATA

ORIGINAL SHEET NO. 8.401.15A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2015 - DECEMBER 2015

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 1	JAN 15	FEB 15	MAR 15	APR 15	MAY 15	JUN 15	JUL 15	AUG 15	SEP 15	OCT 15	NOV 15	DEC 15	2015
1. EAF (%)	63.0	86.8	76.6	93.3	80.0	86.3	72.3	28.0	0.0	0.0	29.1	94.8	59.0
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	532.3	672.0	681.9	719.6	642.6	719.7	720.0	270.5	0.0	0.0	223.4	741.2	5,923.1
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	211.8	0.0	61.1	0.4	101.4	0.3	24.0	473.5	720.0	744.0	497.6	2.8	2,836.9
6. POH	211.8	0.0	0.0	0.0	0.0	0.0	0.0	233.0	720.0	744.0	454.9	0.0	2,363.7
7. FOH	0.0	0.0	61.1	0.4	53.2	0.0	24.0	240.5	0.0	0.0	42.6	2.8	424.6
8. MOH	0.0	0.0	0.0	0.0	48.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	48.6
9. PFOH	506.9	677.8	668.6	705.8	605.8	651.7	715.4	258.0	0.0	0.0	61.4	537.7	5,389.2
10. LR PF (MW)	47.0	51.7	65.2	25.4	28.2	44.0	96.8	90.7	0.0	0.0	84.8	23.3	51.3
11. PMOH	13.4	0.3	6.3	6.3	8.1	51.1	4.6	4.1	0.0	0.0	0.0	8.8	102.8
12. LR PM (MW)	103.4	0.0	175.5	78.1	144.8	177.2	168.6	164.3	0.0	0.0	0.0	173.0	157.1
13. NSC (MW)	395.0	395.0	395.0	385.0	385.0	385.0	385.0	385.0	385.0	385.0	385.0	395.0	388.3
14. OPR BTU(GBTU)	1,839.1	2,360.6	2,350.0	2,664.7	2,375.0	2,381.3	2,277.5	715.5	0.0	0.0	469.8	2,000.7	19,434.3
15. NET GEN (MWH)	172,923	224,631	218,619	252,349	224,991	218,554	196,231	71,912	0	0	39,542	188,566	1,808,318
16. ANOHR (BTU/KWH)	10,635.5	10,509.0	10,749.5	10,559.6	10,556.2	10,895.7	11,606.2	9,949.0	0.0	0.0	11,881.3	10,610.2	10,747.0
17. NOF (%)	82.3	84.6	81.2	91.1	90.9	78.9	70.8	69.0	0.0	0.0	46.0	64.4	78.6
18. NPC (MW)	395.0	395.0	395.0	385.0	385.0	385.0	385.0	385.0	385.0	385.0	385.0	395.0	388.3
19. ANOHR EQUATION	ANOHR = NOF (2.316) + 10,343												

EXHIBIT NO._____ (BSB-1)
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ORIGINAL SHEET NO. 8.401.15A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2015 - DECEMBER 2015

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 15	FEB 15	MAR 15	APR 15	MAY 15	JUN 15	JUL 15	AUG 15	SEP 15	OCT 15	NOV 15	DEC 15	2015
1. EAF (%)	25.9	0.0	36.8	76.2	55.3	0.4	0.0	20.0	81.5	73.0	82.0	95.4	45.8
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	231.3	0.0	345.1	720.0	527.7	2.6	0.0	158.3	602.2	543.9	612.1	744.0	4,487.2
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	512.7	672.0	397.9	0.0	216.3	717.4	744.0	585.7	117.8	200.1	108.9	0.0	4,272.8
6. POH	235.8	0.0	0.0	0.0	137.0	281.4	0.0	0.0	0.0	0.0	0.0	0.0	654.1
7. FOH	276.9	672.0	397.9	0.0	79.3	436.0	744.0	585.7	117.8	65.0	108.9	0.0	3,483.6
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	135.1	0.0	0.0	135.1
9. PFOH	227.3	0.0	339.4	701.7	506.2	0.0	0.0	115.2	143.3	3.2	46.0	508.6	2,590.9
10. LR PF (MW)	67.3	0.0	83.6	90.4	81.7	0.0	0.0	32.2	35.3	75.1	177.6	24.7	68.8
11. PMOH	0.5	0.0	0.0	18.3	21.5	0.0	0.0	0.0	15.5	0.0	0.0	6.0	61.8
12. LR PM (MW)	0.0	0.0	0.0	134.2	160.4	0.0	0.0	0.0	49.3	0.0	0.0	171.5	124.5
13. NSC (MW)	395.0	395.0	395.0	385.0	385.0	385.0	385.0	385.0	385.0	385.0	385.0	395.0	387.9
14. OPR BTU(GBTU)	738.9	0.0	1,079.5	2,183.4	1,635.5	0.0	0.0	298.9	2,035.9	1,818.0	1,961.1	2,154.8	13,906.0
15. NET GEN (MWH)	69,574	0	102,284	203,080	152,610	4	0	32,495	199,727	172,338	188,364	204,972	1,325,448
16. ANOHR (BTU/KWH)	10,619.6	0.0	10,554.4	10,751.3	10,717.1	0.0	0.0	9,197.7	10,193.5	10,549.3	10,411.1	10,512.6	10,492.0
17. NOF (%)	76.1	0.0	75.0	73.3	75.1	0.4	0.0	53.3	86.2	82.3	79.9	69.7	76.1
18. NPC (MW)	395.0	395.0	395.0	385.0	385.0	385.0	385.0	385.0	385.0	385.0	385.0	395.0	388.3
19. ANOHR EQUATION	ANOHR = NOF (-6.562) + 10,987												

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ORIGINAL SHEET NO. 8.401.15A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2015 - DECEMBER 2015

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 15	FEB 15	MAR 15	APR 15	MAY 15	JUN 15	JUL 15	AUG 15	SEP 15	OCT 15	NOV 15	DEC 15	2015
1. EAF (%)	41.7	37.9	0.0	71.5	96.7	93.6	95.6	98.8	66.9	98.2	64.0	97.8	72.2
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	311.0	290.1	0.0	530.7	740.2	706.9	738.1	744.0	509.5	744.0	566.4	744.0	6,625.0
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	433.0	381.9	743.0	189.3	3.8	13.1	5.9	0.0	210.5	0.0	154.6	0.0	2,135.0
6. POH	328.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	328.0
7. FOH	105.0	381.9	743.0	189.3	3.8	13.1	5.9	0.0	210.5	0.0	0.0	0.0	1,652.4
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	154.6	0.0	154.6
9. PFOH	12.5	94.5	0.0	29.5	6.9	79.4	284.9	2.8	199.9	50.8	323.8	17.1	1,102.0
10. LR PF (MW)	19.0	117.3	0.0	166.5	211.8	28.7	18.5	18.8	54.3	76.5	127.9	14.5	74.1
11. PMOH	0.0	26.0	0.0	9.3	34.0	50.2	33.4	26.7	0.0	7.8	0.0	26.9	214.3
12. LR PM (MW)	0.0	118.4	0.0	148.1	197.4	213.5	162.6	134.9	0.0	168.1	0.0	235.7	180.0
13. NSC (MW)	400.0	400.0	400.0	395.0	395.0	395.0	395.0	395.0	395.0	395.0	395.0	400.0	396.7
14. OPR BTU(GBTU)	1,230.4	975.0	0.0	1,897.9	2,936.1	2,654.3	2,670.8	2,668.7	1,614.3	2,501.7	1,602.8	2,256.6	23,008.6
15. NET GEN (MWH)	118,033	96,603	0	182,744	284,110	253,297	257,420	266,585	154,930	241,831	151,651	215,976	2,223,180
16. ANOHR BTU/KWH	10,424.4	10,093.2	0.0	10,385.6	10,334.5	10,478.9	10,375.3	10,010.6	10,419.6	10,344.7	10,569.3	10,448.2	10,349.0
17. NOF (%)	94.9	83.2	0.0	87.2	97.2	90.7	88.3	90.7	77.0	82.3	67.8	72.6	84.6
18. NPC (MW)	400.0	400.0	400.0	395.0	395.0	395.0	395.0	395.0	395.0	395.0	395.0	400.0	396.7
19. ANOHR EQUATION	ANOHR = NOF (-20.119) + 12,356												

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ORIGINAL SHEET NO. 8.401.15A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2015 - DECEMBER 2015

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 15	FEB 15	MAR 15	APR 15	MAY 15	JUN 15	JUL 15	AUG 15	SEP 15	OCT 15	NOV 15	DEC 15	2015
1. EAF (%)	89.3	94.2	71.6	75.1	46.7	99.4	56.2	100.0	96.9	67.3	88.5	90.7	81.1
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	737.2	672.0	690.9	625.1	367.7	720.0	418.9	744.0	720.0	545.3	639.0	744.0	7,624.1
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	6.8	0.0	52.1	94.9	376.3	0.0	325.1	0.0	0.0	198.7	82.0	0.0	1,135.9
6. POH	0.0	0.0	0.0	0.0	334.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	334.1
7. FOH	6.8	0.0	52.1	94.9	8.3	0.0	325.1	0.0	0.0	172.6	82.0	0.0	741.8
8. MOH	0.0	0.0	0.0	0.0	33.9	0.0	0.0	0.0	0.0	26.1	0.0	0.0	60.0
9. PFOH	623.5	385.3	574.2	593.8	111.1	4.4	1.4	0.6	600.7	314.9	19.1	219.0	3,448.1
10. LR PF (MW)	49.6	43.8	114.9	62.2	78.9	188.1	93.1	232.6	15.8	50.3	23.3	83.3	59.3
11. PMOH	5.3	2.0	16.5	0.5	5.3	7.6	1.0	1.3	6.1	18.4	1.3	45.3	110.6
12. LR PM (MW)	265.2	241.9	255.9	0.0	27.9	132.2	139.6	0.0	41.1	206.8	0.0	271.5	214.6
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	438.9
14. OPR BTU(GBTU)	2,913.0	2,749.4	2,353.6	2,425.6	1,361.2	2,890.1	1,674.1	3,148.2	2,886.7	1,947.9	2,304.4	2,079.6	28,733.9
15. NET GEN (MWH)	281,282	265,001	220,972	227,208	132,124	279,714	162,158	307,507	277,454	184,264	228,039	203,385	2,769,108
16. ANOHR BTU/KWH	10,356.0	10,375.0	10,651.3	10,675.5	10,302.7	10,332.2	10,323.7	10,237.9	10,404.2	10,571.5	10,105.5	10,225.1	10,377.0
17. NOF (%)	86.3	89.2	72.4	83.2	82.2	88.9	88.6	94.6	88.2	77.3	81.7	61.8	82.8
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 (-0.940) + 10,508												

EXHIBIT NO._____ (BSB-1)
TAMPA ELECTRIC COMPANY
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ORIGINAL SHEET NO. 8.401.15A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2015 - DECEMBER 2015

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 15	FEB 15	MAR 15	APR 15	MAY 15	JUN 15	JUL 15	AUG 15	SEP 15	OCT 15	NOV 15	DEC 15	2015
1. EAF (%)	99.5	97.4	28.1	0.0	46.4	82.6	84.1	81.4	93.9	43.3	96.0	96.0	70.5
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	740.4	654.6	208.6	0.0	345.2	594.5	625.7	422.0	652.6	322.2	692.5	714.0	5,972.1
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	183.7	23.8	0.0	0.0	0.0	207.5
5. UH	3.6	17.4	534.4	720.0	398.8	125.5	118.3	138.3	43.6	421.8	28.5	30.0	2,580.4
6. POH	0.0	0.0	534.4	644.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,178.4
7. FOH	3.6	17.4	0.0	76.0	398.8	8.8	118.3	131.0	43.6	421.8	28.5	30.0	1,278.0
8. MOH	0.0	0.0	0.0	0.0	0.0	116.8	0.0	7.3	0.0	0.0	0.0	0.0	124.1
9. PFOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13. NSC (MW)	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0
14. OPR BTU(GBTU)	1,637.4	1,517.2	433.3	0.3	538.1	846.0	1,336.3	1,010.9	1,444.9	721.7	1,544.2	1,676.9	12,707.2
15. NET GEN (MWH)	164,627	147,869	43,671	-4,977	60,354	89,147	133,922	91,110	141,235	66,099	149,054	155,269	1,237,380
16. ANOHR BTU/KWH	9,946.3	10,260.7	9,921.4	0.0	8,916.3	9,490.2	9,978.1	11,095.1	10,230.2	10,918.9	10,360.2	10,799.7	10,269.0
17. NOF (%)	101.1	102.7	95.2	0.0	79.5	68.2	97.3	98.1	98.4	93.3	97.8	98.8	94.2
18. NPC (MW)	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0
19. ANOHR EQUATION	ANOHR = NOF (-47.266) + 15,117												

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ORIGINAL SHEET NO. 8.401.15A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2015 - DECEMBER 2015

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 15	FEB 15	MAR 15	APR 15	MAY 15	JUN 15	JUL 15	AUG 15	SEP 15	OCT 15	NOV 15	DEC 15	2015
1. EAF (%)	96.5	91.5	100.0	54.5	98.3	99.7	98.2	98.0	98.9	68.8	26.7	98.9	85.9
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	415.9	663.6	743.0	418.7	744.0	720.0	744.0	739.4	720.0	540.6	177.6	735.5	7,362.3
4. RSH	328.1	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	14.9	0.0	343.4
5. UH	0.0	8.4	0.0	300.9	0.0	0.0	0.0	4.6	0.0	203.4	528.5	8.5	1,054.3
6. POH	0.0	0.0	0.0	300.9	0.0	0.0	0.0	0.0	0.0	203.4	528.5	0.0	1,032.8
7. FOH	0.0	8.4	0.0	0.0	0.0	0.0	0.0	4.6	0.0	0.0	0.0	0.0	13.0
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.5	8.5
9. PFOH	30.6	146.5	0.0	7.7	31.7	0.7	0.0	23.0	13.5	32.5	0.0	0.6	286.8
10. LR PF (MW)	264.0	264.0	0.0	233.7	233.7	233.7	0.0	233.7	233.7	233.7	0.0	9.9	251.9
11. PMOH	47.0	0.0	0.0	720.0	6.9	5.3	39.1	9.0	11.2	53.2	0.0	0.0	891.6
12. LR PM (MW)	264.0	0.0	0.0	23.4	233.7	233.7	233.7	233.7	233.7	233.7	0.0	0.0	65.5
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)	1,180.6	2,396.4	2,947.0	1,419.8	2,689.6	2,837.4	2,923.9	2,834.3	2,787.2	1,971.4	549.9	2,383.2	26,920.7
15. NET GEN (MWH)	157,484	320,208	401,081	189,512	363,344	387,907	396,532	387,939	383,082	269,481	71,872	320,827	3,649,270
16. ANOHR (BTU/KWH)	7,496.5	7,483.7	7,347.7	7,491.9	7,402.4	7,314.6	7,373.8	7,306.1	7,275.8	7,315.4	7,650.6	7,428.3	7,377.0
17. NOF (%)	47.8	60.9	68.2	64.6	69.7	76.9	76.0	74.8	75.9	71.1	57.7	55.1	67.8
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 (-12.819) + 8,084												

ORIGINAL SHEET NO. 8.401.15A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2015 - DECEMBER 2015

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 15	FEB 15	MAR 15	APR 15	MAY 15	JUN 15	JUL 15	AUG 15	SEP 15	OCT 15	NOV 15	DEC 15	2015
1. EAF (%)	97.7	73.7	73.0	99.5	97.1	99.7	98.7	94.7	96.2	100.0	80.5	58.7	89.2
2. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
3. SH	731.8	304.8	562.9	720.0	744.0	720.0	744.0	744.0	720.0	744.0	580.5	440.0	7,756.1
4. RSH	12.2	221.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	234.2
5. UH	0.0	145.2	180.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	140.5	304.0	769.7
6. POH	0.0	145.2	180.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	301.8	627.1
7. FOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	140.5	2.1	142.6
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PFOH	25.8	2.7	18.5	15.0	80.1	7.2	1.9	3.8	0.2	0.0	0.0	3.3	158.5
10. LR PF (MW)	261.8	261.8	261.8	232.3	232.3	232.3	232.3	232.3	232.3	0.0	0.0	261.8	241.6
11. PMOH	43.9	672.0	553.0	0.0	7.4	0.0	37.4	154.5	108.9	0.0	0.0	2.7	1,579.9
12. LR PM (MW)	261.8	47.7	30.2	0.0	232.3	0.0	232.3	232.3	232.3	0.0	0.0	1,047.0	85.2
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)	3,120.6	1,392.9	2,668.5	3,603.2	3,527.2	3,730.5	4,141.5	3,920.5	3,692.9	4,103.0	3,446.3	1,623.7	38,970.9
15. NET GEN (MWH)	416,548	184,652	358,379	475,545	475,533	507,368	562,236	537,122	507,647	558,978	465,744	217,411	5,267,164
16. ANOHR (BTU/KWH)	7,491.6	7,543.4	7,446.1	7,576.9	7,417.4	7,352.7	7,366.0	7,299.2	7,274.6	7,340.2	7,399.5	7,468.3	7,399.0
17. NOF (%)	54.4	57.9	60.8	71.1	68.8	75.9	81.3	77.7	75.9	80.9	86.4	47.2	70.1
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 (-7.052) + 7,811												

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GPIF 2017 PROJECTION FILING
EXHIBIT NO. BSB-2
DOCUMENT NO. 1

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCUMENT NO. 1

GPIF SCHEDULES

JANUARY 2017 – DECEMBER 2017

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 53
PARTY: TAMPA ELECTRIC COMPANY – (DIRECT)
DESCRIPTION: Brian S. Buckley BSB-2

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2017 - DECEMBER 2017
TARGETS
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TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE
JANUARY 2017 - DECEMBER 2017

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	18,187.7	9,093.9
+9	16,369.0	8,184.5
+8	14,550.2	7,275.1
+7	12,731.4	6,365.7
+6	10,912.6	5,456.3
+5	9,093.9	4,546.9
+4	7,275.1	3,637.5
+3	5,456.3	2,728.2
+2	3,637.5	1,818.8
+1	1,818.8	909.4
0	0.0	0.0
-1	(2,581.8)	(909.4)
-2	(5,163.6)	(1,818.8)
-3	(7,745.4)	(2,728.2)
-4	(10,327.2)	(3,637.5)
-5	(12,908.9)	(4,546.9)
-6	(15,490.7)	(5,456.3)
-7	(18,072.5)	(6,365.7)
-8	(20,654.3)	(7,275.1)
-9	(23,236.1)	(8,184.5)
-10	(25,817.9)	(9,093.9)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
JANUARY 2017 - DECEMBER 2017

Line 1	Beginning of period balance of common equity: End of month common equity:		$2,425,777,000
Line 2	Month of January	2017	$2,366,384,000
Line 3	Month of February	2017	$2,386,596,863
Line 4	Month of March	2017	$2,406,982,378
Line 5	Month of April	2017	$2,446,336,641
Line 6	Month of May	2017	$2,467,232,433
Line 7	Month of June	2017	$2,488,306,710
Line 8	Month of July	2017	$2,428,236,665
Line 9	Month of August	2017	$2,448,977,853
Line 10	Month of September	2017	$2,469,896,205
Line 11	Month of October	2017	$2,509,403,740
Line 12	Month of November	2017	$2,530,838,231
Line 13	Month of December	2017	$2,552,455,807
Line 14	(Summation of line 1 through line 13 divided by 13)		$2,455,955,733
Line 15	25 Basis points		0.0025
Line 16	Revenue Expansion Factor		61.27%
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$10,021,516
Line 18	Jurisdictional Sales		19,114,079 MWH
Line 19	Total Sales		19,128,439 MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)		99.92%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)		$10,013,992
Line 22	Incentive Cap (50% of projected fuel savings at 10 GPIF-point level from Sheet No. 3.515)		$9,093,869
Line 23	Maximum Allowed GPIF Reward (at 10 GPIF-point level) (the lesser of line 21 and line 22)		$9,093,869

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 2017 - DECEMBER 2017

EQUIVALENT AVAILABILITY

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 1	6.61%	80.5	83.4	74.7	1,202.8	(2,645.5)
BIG BEND 2	8.70%	69.6	74.7	59.4	1,583.0	(2,015.7)
BIG BEND 3	5.55%	61.4	65.8	52.6	1,008.9	(2,918.2)
BIG BEND 4	7.82%	79.1	82.3	72.7	1,422.8	(2,981.1)
POLK 1	4.29%	82.1	84.6	77.2	779.9	(1,476.4)
BAYSIDE 1	2.74%	75.3	77.5	71.0	498.6	(1,194.0)
BAYSIDE 2	0.62%	76.1	78.0	72.4	113.7	(1,008.8)
GPIF SYSTEM	**36.34%**					

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 1	9.22%	10,698	87.7	10,409	10,987	1,677.5	(1,677.5)
BIG BEND 2	12.61%	10,545	86.9	10,098	10,992	2,294.1	(2,294.1)
BIG BEND 3	6.25%	10,588	84.3	10,324	10,852	1,136.4	(1,136.4)
BIG BEND 4	7.20%	10,447	82.0	10,243	10,652	1,309.3	(1,309.3)
POLK 1	7.01%	10,048	97.3	9,528	10,568	1,275.5	(1,275.5)
BAYSIDE 1	9.33%	7,517	52.7	7,382	7,653	1,697.4	(1,697.4)
BAYSIDE 2	12.03%	7,683	32.6	7,504	7,862	2,187.7	(2,187.7)
GPIF SYSTEM	**63.66%**						

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS PRIOR PERIOD ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 17 - DEC 17 POF	TARGET PERIOD JAN 17 - DEC 17 EUOF	TARGET PERIOD JAN 17 - DEC 17 EUOR	ACTUAL PERFORMANCE JAN 15 - DEC 15 POF	ACTUAL PERFORMANCE JAN 15 - DEC 15 EUOF	ACTUAL PERFORMANCE JAN 15 - DEC 15 EUOR	ACTUAL PERFORMANCE JAN 14 - DEC 14 POF	ACTUAL PERFORMANCE JAN 14 - DEC 14 EUOF	ACTUAL PERFORMANCE JAN 14 - DEC 14 EUOR	ACTUAL PERFORMANCE JAN 13 - DEC 13 POF	ACTUAL PERFORMANCE JAN 13 - DEC 13 EUOF	ACTUAL PERFORMANCE JAN 13 - DEC 13 EUOR
BIG BEND 1	6.61%	18.2%	6.6	12.9	13.8	27.0	14.0	19.2	5.6	10.8	11.5	10.8	17.6	19.8
BIG BEND 2	8.70%	24.0%	6.6	23.8	25.5	7.5	46.8	50.5	8.4	10.6	11.6	6.1	18.3	19.5
BIG BEND 3	5.55%	15.3%	21.9	16.7	21.3	3.7	24.1	25.0	5.1	15.8	16.7	25.0	8.5	11.3
BIG BEND 4	7.82%	21.5%	6.6	14.3	15.3	3.8	15.1	15.7	20.7	11.2	14.2	4.8	17.6	18.5
POLK 1	4.29%	11.8%	7.4	10.5	11.3	13.5	16.0	19.0	5.0	8.7	10.6	15.3	6.7	8.8
BAYSIDE 1	2.74%	7.5%	18.6	6.1	7.5	11.8	2.3	2.7	6.2	11.5	14.1	3.8	7.5	8.7
BAYSIDE 2	0.62%	1.7%	19.5	4.4	5.5	7.2	3.7	4.1	5.0	5.4	5.7	4.1	12.2	13.1
GPIF SYSTEM	**36.34%**	**100.0%**	**10.1**	**15.5**	**17.2**	**10.7**	**22.8**	**25.3**	**9.4**	**11.3**	**12.9**	**10.4**	**14.2**	**15.9**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**74.4**			**66.5**			**79.3**			**75.3**	

3 PERIOD AVERAGE POF	3 PERIOD AVERAGE EUOF	3 PERIOD AVERAGE EUOR	3 PERIOD AVERAGE EAF
10.2	**16.1**	**18.0**	**73.7**

AVERAGE NET OPERATING HEAT RATE (Btu/kWh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 17 - DEC 17	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 15 - DEC 15	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 14 - DEC 14	ADJUSTED ACTUAL PERFORMANCE HEAT RATE JAN 13 - DEC 13
BIG BEND 1	9.22%	14.5%	10,698	10,600	10,594	10,535
BIG BEND 2	12.61%	19.8%	10,545	10,428	10,313	10,339
BIG BEND 3	6.25%	9.8%	10,588	10,352	10,437	10,567
BIG BEND 4	7.20%	11.3%	10,447	10,381	10,275	10,482
POLK 1	7.01%	11.0%	10,048	10,298	10,167	10,618
BAYSIDE 1	9.33%	14.7%	7,517	7,525	7,470	7,379
BAYSIDE 2	12.03%	18.9%	7,683	7,696	7,640	7,614
GPIF SYSTEM	**63.66%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kWh)			**9,521**	**9,484**	**9,424**	**9,488**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2017 - DECEMBER 2017
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_1 BIG BEND 1	695,758.1	694,555.3	1,202.8	6.61%
EA_2 BIG BEND 2	695,758.1	694,175.0	1,583.0	8.70%
EA_3 BIG BEND 3	695,758.1	694,749.2	1,008.9	5.55%
EA_4 BIG BEND 4	695,758.1	694,335.3	1,422.8	7.82%
EA_5 POLK 1	695,758.1	694,978.2	779.9	4.29%
EA_6 BAYSIDE 1	695,758.1	695,259.5	498.6	2.74%
EA_7 BAYSIDE 2	695,758.1	695,644.4	113.7	0.62%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	695,758.1	694,080.5	1,677.5	9.22%
AHR_2 BIG BEND 2	695,758.1	693,463.9	2,294.1	12.61%
AHR_3 BIG BEND 3	695,758.1	694,621.7	1,136.4	6.25%
AHR_4 BIG BEND 4	695,758.1	694,448.7	1,309.3	7.20%
AHR_5 POLK 1	695,758.1	694,482.6	1,275.5	7.01%
AHR_6 BAYSIDE 1	695,758.1	694,060.6	1,697.4	9.33%
AHR_7 BAYSIDE 2	695,758.1	693,570.3	2,187.7	12.03%
TOTAL SAVINGS			**18,187.7**	**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 2017 - DECEMBER 2017

BIG BEND 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	1,202.8	83.4	+10	1,677.5	10,409
+9	1,082.5	83.1	+9	1,509.8	10,430
+8	962.2	82.9	+8	1,342.0	10,451
+7	841.9	82.6	+7	1,174.3	10,473
+6	721.7	82.3	+6	1,006.5	10,494
+5	601.4	82.0	+5	838.8	10,516
+4	481.1	81.7	+4	671.0	10,537
+3	360.8	81.4	+3	503.3	10,559
+2	240.6	81.1	+2	335.5	10,580
+1	120.3	80.8	+1	167.8	10,601
					10,623
0	0.0	80.5	0	0.0	10,698
					10,773
-1	(264.6)	79.9	-1	(167.8)	10,794
-2	(529.1)	79.4	-2	(335.5)	10,816
-3	(793.7)	78.8	-3	(503.3)	10,837
-4	(1,058.2)	78.2	-4	(671.0)	10,859
-5	(1,322.8)	77.6	-5	(838.8)	10,880
-6	(1,587.3)	77.0	-6	(1,006.5)	10,901
-7	(1,851.9)	76.5	-7	(1,174.3)	10,923
-8	(2,116.4)	75.9	-8	(1,342.0)	10,944
-9	(2,381.0)	75.3	-9	(1,509.8)	10,966
-10	(2,645.5)	74.7	-10	(1,677.5)	10,987
	Weighting Factor =	6.61%		Weighting Factor =	9.22%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2017 - DECEMBER 2017

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	1,583.0	74.7	+10	2,294.1	10,098
+9	1,424.7	74.2	+9	2,064.7	10,135
+8	1,266.4	73.7	+8	1,835.3	10,172
+7	1,108.1	73.1	+7	1,605.9	10,209
+6	949.8	72.6	+6	1,376.5	10,247
+5	791.5	72.1	+5	1,147.1	10,284
+4	633.2	71.6	+4	917.7	10,321
+3	474.9	71.1	+3	688.2	10,358
+2	316.6	70.6	+2	458.8	10,396
+1	158.3	70.1	+1	229.4	10,433
					10,470
0	0.0	69.6	0	0.0	10,545
					10,620
-1	(201.6)	68.6	-1	(229.4)	10,657
-2	(403.1)	67.5	-2	(458.8)	10,695
-3	(604.7)	66.5	-3	(688.2)	10,732
-4	(806.3)	65.5	-4	(917.7)	10,769
-5	(1,007.9)	64.5	-5	(1,147.1)	10,806
-6	(1,209.4)	63.5	-6	(1,376.5)	10,843
-7	(1,411.0)	62.4	-7	(1,605.9)	10,881
-8	(1,612.6)	61.4	-8	(1,835.3)	10,918
-9	(1,814.1)	60.4	-9	(2,064.7)	10,955
-10	(2,015.7)	59.4	-10	(2,294.1)	10,992
	Weighting Factor =	8.70%		Weighting Factor =	12.61%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2017 - DECEMBER 2017

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	1,008.9	65.8	+10	1,136.4	10,324
+9	908.0	65.4	+9	1,022.7	10,343
+8	807.1	65.0	+8	909.1	10,361
+7	706.2	64.5	+7	795.5	10,380
+6	605.4	64.1	+6	681.8	10,399
+5	504.5	63.6	+5	568.2	10,418
+4	403.6	63.2	+4	454.6	10,437
+3	302.7	62.7	+3	340.9	10,456
+2	201.8	62.3	+2	227.3	10,475
+1	100.9	61.9	+1	113.6	10,494
					10,513
0	0.0	61.4	0	0.0	10,588
					10,663
-1	(291.8)	60.5	-1	(113.6)	10,682
-2	(583.6)	59.6	-2	(227.3)	10,701
-3	(875.5)	58.8	-3	(340.9)	10,720
-4	(1,167.3)	57.9	-4	(454.6)	10,738
-5	(1,459.1)	57.0	-5	(568.2)	10,757
-6	(1,750.9)	56.1	-6	(681.8)	10,776
-7	(2,042.7)	55.2	-7	(795.5)	10,795
-8	(2,334.5)	54.3	-8	(909.1)	10,814
-9	(2,626.4)	53.4	-9	(1,022.7)	10,833
-10	(2,918.2)	52.6	-10	(1,136.4)	10,852
	Weighting Factor =	5.55%		Weighting Factor =	6.25%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2017 - DECEMBER 2017

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	1,422.8	82.3	+10	1,309.3	10,243
+9	1,280.5	82.0	+9	1,178.4	10,256
+8	1,138.2	81.6	+8	1,047.5	10,269
+7	995.9	81.3	+7	916.5	10,282
+6	853.7	81.0	+6	785.6	10,295
+5	711.4	80.7	+5	654.7	10,308
+4	569.1	80.4	+4	523.7	10,320
+3	426.8	80.0	+3	392.8	10,333
+2	284.6	79.7	+2	261.9	10,346
+1	142.3	79.4	+1	130.9	10,359
					10,372
0	0.0	79.1	0	0.0	10,447
					10,522
-1	(298.1)	78.4	-1	(130.9)	10,535
-2	(596.2)	77.8	-2	(261.9)	10,548
-3	(894.3)	77.2	-3	(392.8)	10,561
-4	(1,192.5)	76.5	-4	(523.7)	10,574
-5	(1,490.6)	75.9	-5	(654.7)	10,587
-6	(1,788.7)	75.2	-6	(785.6)	10,600
-7	(2,086.8)	74.6	-7	(916.5)	10,613
-8	(2,384.9)	74.0	-8	(1,047.5)	10,626
-9	(2,683.0)	73.3	-9	(1,178.4)	10,639
-10	(2,981.1)	72.7	-10	(1,309.3)	10,652
	Weighting Factor =	7.82%		Weighting Factor =	7.20%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2017 - DECEMBER 2017

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	779.9	84.6	+10	1,275.5	9,528
+9	701.9	84.3	+9	1,148.0	9,572
+8	623.9	84.1	+8	1,020.4	9,617
+7	545.9	83.8	+7	892.9	9,661
+6	467.9	83.6	+6	765.3	9,706
+5	389.9	83.3	+5	637.8	9,750
+4	311.9	83.1	+4	510.2	9,795
+3	234.0	82.8	+3	382.7	9,839
+2	156.0	82.6	+2	255.1	9,884
+1	78.0	82.3	+1	127.6	9,928
					9,973
0	0.0	82.1	0	0.0	10,048
					10,123
-1	(147.6)	81.6	-1	(127.6)	10,167
-2	(295.3)	81.1	-2	(255.1)	10,212
-3	(442.9)	80.6	-3	(382.7)	10,256
-4	(590.5)	80.1	-4	(510.2)	10,301
-5	(738.2)	79.6	-5	(637.8)	10,345
-6	(885.8)	79.1	-6	(765.3)	10,390
-7	(1,033.5)	78.6	-7	(892.9)	10,434
-8	(1,181.1)	78.1	-8	(1,020.4)	10,479
-9	(1,328.7)	77.7	-9	(1,148.0)	10,523
-10	(1,476.4)	77.2	-10	(1,275.5)	10,568
	Weighting Factor =	4.29%		Weighting Factor =	7.01%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2017 - DECEMBER 2017

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	498.6	77.5	+10	1,697.4	7,382
+9	448.8	77.2	+9	1,527.7	7,388
+8	398.9	77.0	+8	1,357.9	7,394
+7	349.0	76.8	+7	1,188.2	7,400
+6	299.2	76.6	+6	1,018.5	7,406
+5	249.3	76.4	+5	848.7	7,412
+4	199.4	76.2	+4	679.0	7,418
+3	149.6	76.0	+3	509.2	7,424
+2	99.7	75.7	+2	339.5	7,430
+1	49.9	75.5	+1	169.7	7,436
					7,442
0	0.0	75.3	0	0.0	7,517
					7,592
-1	(119.4)	74.9	-1	(169.7)	7,598
-2	(238.8)	74.5	-2	(339.5)	7,604
-3	(358.2)	74.0	-3	(509.2)	7,610
-4	(477.6)	73.6	-4	(679.0)	7,616
-5	(597.0)	73.2	-5	(848.7)	7,622
-6	(716.4)	72.7	-6	(1,018.5)	7,628
-7	(835.8)	72.3	-7	(1,188.2)	7,635
-8	(955.2)	71.9	-8	(1,357.9)	7,641
-9	(1,074.6)	71.4	-9	(1,527.7)	7,647
-10	(1,194.0)	71.0	-10	(1,697.4)	7,653
	Weighting Factor =	2.74%		Weighting Factor =	9.33%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2017 - DECEMBER 2017

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	113.7	78.0	+10	2,187.7	7,504
+9	102.3	77.8	+9	1,969.0	7,515
+8	90.9	77.6	+8	1,750.2	7,525
+7	79.6	77.4	+7	1,531.4	7,535
+6	68.2	77.2	+6	1,312.6	7,546
+5	56.8	77.0	+5	1,093.9	7,556
+4	45.5	76.8	+4	875.1	7,567
+3	34.1	76.6	+3	656.3	7,577
+2	22.7	76.5	+2	437.5	7,587
+1	11.4	76.3	+1	218.8	7,598
					7,608
0	0.0	76.1	0	0.0	7,683
					7,758
-1	(100.9)	75.7	-1	(218.8)	7,768
-2	(201.8)	75.3	-2	(437.5)	7,779
-3	(302.7)	75.0	-3	(656.3)	7,789
-4	(403.5)	74.6	-4	(875.1)	7,800
-5	(504.4)	74.2	-5	(1,093.9)	7,810
-6	(605.3)	73.9	-6	(1,312.6)	7,820
-7	(706.2)	73.5	-7	(1,531.4)	7,831
-8	(807.1)	73.1	-8	(1,750.2)	7,841
-9	(908.0)	72.7	-9	(1,969.0)	7,851
-10	(1,008.8)	72.4	-10	(2,187.7)	7,862
	Weighting Factor =	0.62%		Weighting Factor =	12.03%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2017 - DECEMBER 2017

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 1	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017
1. EAF (%)	75.1	55.4	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	86.2	58.4	80.5
2. POF	12.9	35.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.3	6.6
3. EUOF	12.0	8.9	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	9.4	12.9
4. EUOR	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	391	273	544	557	422	560	582	572	561	566	299	304	5,631
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	353	399	199	163	322	160	162	172	159	178	422	440	3,129
9. POH	96	240	0	0	0	0	0	0	0	0	0	240	576
10. EFOH	71	48	82	79	82	79	82	82	79	82	79	55	900
11. EMOH	18	12	21	20	21	20	21	21	20	21	20	14	230
12. OPER BTU (GBTU)	1,408	1,033	2,095	2,040	1,511	1,994	2,076	2,040	2,021	2,033	1,090	1,168	20,514
13. NET GEN (MWH)	131,070	96,850	197,020	191,140	141,080	185,950	193,730	190,300	188,830	189,850	102,010	109,760	1,917,590
14. ANOHR (Btu/kwh)	10,743	10,664	10,635	10,675	10,712	10,721	10,717	10,718	10,702	10,707	10,683	10,639	10,698
15. NOF (%)	84.9	89.8	91.7	89.1	86.8	86.2	86.5	86.4	87.4	87.1	88.6	91.4	87.7
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388
17. ANOHR EQUATION	ANOHR = NOF(	-15.843	) +	12,087									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2017 - DECEMBER 2017

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-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017
1. EAF (%)	67.3	45.2	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5	74.5	50.4	69.6
2. POF	9.7	39.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.3	6.6
3. EUOF	23.1	15.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	17.3	23.8
4. EUOR	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	541	305	591	541	485	553	560	587	576	598	489	332	6,158
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	203	367	152	179	259	167	184	157	144	146	232	412	2,602
9. POH	72	264	0	0	0	0	0	0	0	0	0	240	576
10. EFOH	150	91	166	161	166	161	166	166	161	166	161	112	1,825
11. EMOH	22	13	24	23	24	23	24	24	23	24	23	16	264
12. OPER BTU (GBTU)	1,900	1,175	2,089	1,906	1,711	1,948	1,957	2,080	2,132	2,132	1,735	1,152	21,921
13. NET GEN (MWH)	179,920	111,840	197,880	180,720	162,270	184,740	185,480	197,280	202,680	202,330	164,580	109,040	2,078,760
14. ANOHR (Btu/kwh)	10,561	10,510	10,558	10,546	10,545	10,546	10,550	10,543	10,518	10,539	10,542	10,568	10,545
15. NOF (%)	84.2	92.8	84.8	86.8	86.9	86.8	86.0	87.3	91.4	87.9	87.4	83.1	86.9
16. NPC (MW)	395	395	395	385	385	385	385	385	385	385	385	395	388
17. ANOHR EQUATION	ANOHR = NOF(		-5.963	) +	11,063								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2017 - DECEMBER 2017

PLANT/UNIT	MONTH OF	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 3	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017
1. EAF (%)	78.7	78.7	78.7	70.8	0.0	0.0	63.4	78.7	78.7	78.7	76.0	55.8	61.4
2. POF	0.0	0.0	0.0	10.0	100.0	100.0	19.4	0.0	0.0	0.0	3.3	29.0	21.9
3. EUOF	21.3	21.3	21.3	19.2	0.0	0.0	17.2	21.3	21.3	21.3	20.6	15.1	16.7
4. EUOR	21.3	21.3	21.3	21.3	0.0	0.0	21.3	21.3	21.3	21.3	21.3	21.3	21.3
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	634	573	626	500	0	0	433	630	572	626	501	357	5,452
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	110	99	117	220	744	720	311	114	148	118	220	387	3,308
9. POH	0	0	0	72	744	720	144	0	0	0	24	216	1,920
10. EFOH	146	132	146	127	0	0	118	146	142	146	137	104	1,346
11. EMOH	12	11	12	11	0	0	10	12	12	12	12	9	114
12. OPER BTU (GBTU)	2,192	2,058	2,207	1,726	0	0	1,531	2,280	2,052	2,141	1,786	1,320	19,292
13. NET GEN (MWH)	206,650	194,410	208,290	162,870	0	0	144,640	215,650	193,990	201,840	168,800	124,970	1,822,110
14. ANOHR (Btu/kwh)	10,607	10,584	10,595	10,600	0	0	10,586	10,571	10,577	10,606	10,581	10,565	10,588
15. NOF (%)	81.5	84.8	83.2	82.5	0.0	0.0	84.6	86.7	85.9	81.6	85.3	87.5	84.3
16. NPC (MW)	400	400	400	395	395	395	395	395	395	395	395	400	397
17. ANOHR EQUATION	ANOHR = NOF(	-6.885	) +	11,168									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2017 - DECEMBER 2017

PLANT/UNIT	MONTH OF	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 4	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017
1. EAF (%)	84.7	45.3	81.9	84.7	84.7	84.7	84.7	84.7	84.7	84.7	56.5	84.7	79.1
2. POF	0.0	46.4	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.3	0.0	6.6
3. EUOF	15.3	8.2	14.9	15.3	15.3	15.3	15.3	15.3	15.3	15.3	10.2	15.3	14.3
4. EUOR	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	345	175	224	466	604	576	580	596	484	483	267	612	5,412
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	399	497	519	254	140	144	164	148	236	261	454	132	3,348
9. POH	0	312	24	0	0	0	0	0	0	0	240	0	576
10. EFOH	83	40	80	80	83	80	83	83	80	83	54	83	915
11. EMOH	31	15	30	30	31	30	31	31	30	31	20	31	341
12. OPER BTU (GBTU)	1,293	733	796	1,725	2,280	2,162	2,163	2,215	1,877	1,810	989	2,294	20,337
13. NET GEN (MWH)	123,680	70,460	75,960	165,050	218,320	206,930	206,960	211,940	179,970	173,280	94,630	219,440	1,946,620
14. ANOHR (Btu/kwh)	10,452	10,402	10,474	10,452	10,444	10,446	10,449	10,450	10,432	10,447	10,452	10,452	10,447
15. NOF (%)	81.1	91.1	76.7	81.0	82.7	82.2	81.7	81.4	85.1	82.1	81.1	81.1	82.0
16. NPC (MW)	442	442	442	437	437	437	437	437	437	437	437	442	439
17. ANOHR EQUATION	ANOHR = NOF(	-4.982	) +	10,856									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2017 - DECEMBER 2017

PLANT/UNIT	MONTH OF	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
POLK 1	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017
1. EAF (%)	88.7	88.7	31.5	88.7	88.7	88.7	88.7	88.7	88.7	88.7	67.9	88.7	82.1
2. POF	0.0	0.0	64.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.4	0.0	7.4
3. EUOF	11.3	11.3	4.0	11.3	11.3	11.3	11.3	11.3	11.3	11.3	8.7	11.3	10.5
4. EUOR	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	656	592	250	653	656	653	656	674	634	687	504	656	7,271
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	88	80	493	67	88	67	88	70	86	57	217	88	1,489
9. POH	0	0	479	0	0	0	0	0	0	0	169	0	648
10. EFOH	70	63	25	68	70	68	70	70	68	70	52	70	762
11. EMOH	14	13	5	14	14	14	14	14	14	14	11	14	158
12. OPER BTU (GBTU)	1,413	1,275	535	1,401	1,413	1,401	1,413	1,447	1,366	1,471	1,082	1,413	15,631
13. NET GEN (MWH)	140,610	126,910	53,260	139,470	140,610	139,470	140,610	144,000	135,970	146,420	107,740	140,610	1,555,680
14. ANOHR (Btu/kwh)	10,049	10,049	10,044	10,046	10,049	10,046	10,049	10,046	10,050	10,044	10,047	10,049	10,048
15. NOF (%)	97.4	97.4	96.8	97.1	97.4	97.1	97.4	97.1	97.5	96.9	97.2	97.4	97.3
16. NPC (MW)	220	220	220	220	220	220	220	220	220	220	220	220	220
17. ANOHR EQUATION	ANOHR = NOF(	9.523	) +	9,121									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2017 - DECEMBER 2017

PLANT/UNIT	MONTH OF	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 1	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017
1. EAF (%)	92.5	43.0	0.0	61.7	92.5	92.5	92.5	92.5	92.5	92.5	80.2	68.7	75.3
2. POF	0.0	53.6	100.0	33.3	0.0	0.0	0.0	0.0	0.0	0.0	13.3	25.8	18.6
3. EUOF	7.5	3.5	0.0	5.0	7.5	7.5	7.5	7.5	7.5	7.5	6.5	5.5	6.1
4. EUOR	7.5	7.5	0.0	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	230	289	0	374	646	666	689	649	666	689	516	320	5,734
7. RSH	459	0	0	70	43	0	0	40	0	0	62	191	863
8. UH	55	383	743	276	55	54	55	55	54	55	143	233	2,163
9. POH	0	360	743	240	0	0	0	0	0	0	96	192	1,631
10. EFOH	24	10	0	15	24	23	24	24	23	24	20	18	226
11. EMOH	32	13	0	21	32	31	32	32	31	32	27	24	305
12. OPER BTU (GBTU)	810	828	0	923	1,987	2,286	2,172	1,923	1,942	1,808	1,208	662	16,604
13. NET GEN (MWH)	108,720	109,470	0	121,820	266,470	309,620	291,880	257,060	259,280	239,540	158,920	85,990	2,208,770
14. ANOHR (Btu/kwh)	7,448	7,566	0	7,579	7,456	7,382	7,441	7,480	7,489	7,548	7,604	7,703	7,517
15. NOF (%)	59.7	47.8	0.0	46.5	58.8	66.3	60.4	56.5	55.5	49.6	43.9	33.9	52.7
16. NPC (MW)	792	792	792	701	701	701	701	701	701	701	701	792	731
17. ANOHR EQUATION	ANOHR = NOF(	-9.906	) +	8,039									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2017 - DECEMBER 2017

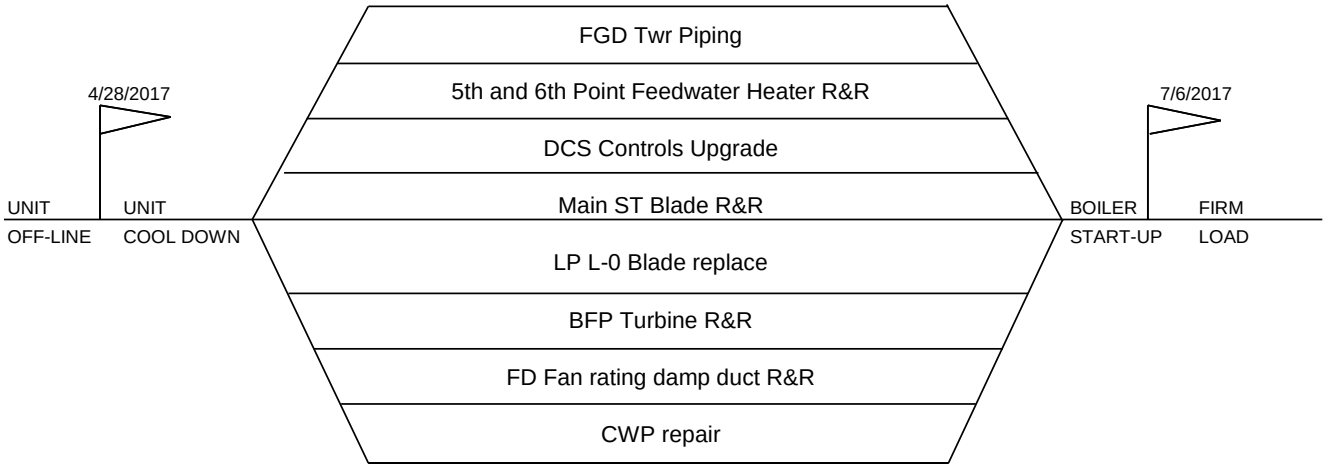
PLANT/UNIT	MONTH OF	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BAYSIDE 2	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017
1. EAF (%)	94.5	94.5	94.5	47.2	94.5	94.5	94.5	94.5	78.7	0.0	31.4	94.5	76.1
2. POF	0.0	0.0	0.0	50.0	0.0	0.0	0.0	0.0	16.7	100.0	66.7	0.0	19.5
3. EUOF	5.5	5.5	5.5	2.8	5.5	5.5	5.5	5.5	4.6	0.0	1.8	5.5	4.4
4. EUOR	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	0.0	5.5	5.5	5.5
5. PH	744	672	743	720	744	720	744	744	720	744	721	744	8,760
6. SH	703	635	702	340	703	680	703	703	567	0	227	703	6,666
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	41	37	41	380	41	40	41	41	153	744	494	41	2,095
9. POH	0	0	0	360	0	0	0	0	120	744	481	0	1,705
10. EFOH	14	13	14	7	14	14	14	14	11	0	5	14	135
11. EMOH	27	24	27	13	27	26	27	27	22	0	9	27	255
12. OPER BTU (GBTU)	1,307	1,021	1,566	712	2,062	2,294	2,033	2,024	1,361	0	454	1,290	16,164
13. NET GEN (MWH)	168,480	131,140	202,770	92,380	270,870	303,320	266,890	265,670	177,300	0	58,790	166,180	2,103,790
14. ANOHR (Btu/kwh)	7,759	7,783	7,722	7,709	7,614	7,563	7,619	7,620	7,675	0	7,719	7,761	7,683
15. NOF (%)	22.9	19.7	27.6	29.2	41.5	48.0	40.9	40.7	33.7	0.0	27.9	22.6	32.6
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(	-7.777	) +	7,937									

TAMPA ELECTRIC COMPANY
ESTIMATED PLANNED OUTAGE SCHEDULE
GPIF UNITS
JANUARY 2017 - DECEMBER 2017

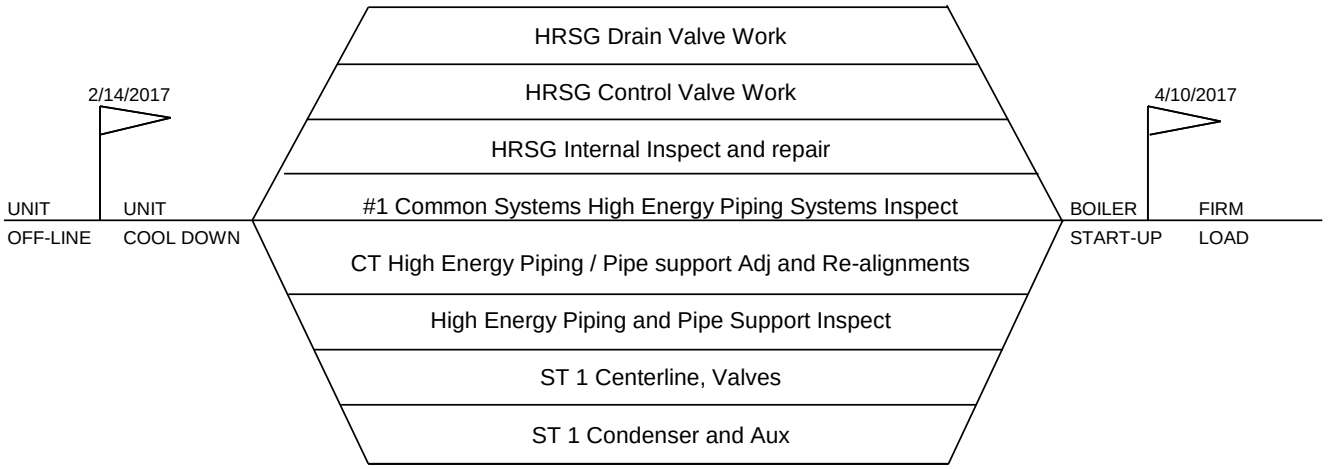
	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
	BIG BEND 1	Jan 28	-	Feb 10	Fuel System Cleanup and FGD/SCR work
		Dec 12	-	Dec 21	Fuel System Cleanup and FGD/SCR work
	BIG BEND 2	Jan 29	-	Feb 11	Fuel System Cleanup and FGD/SCR work
		Dec 13	-	Dec 22	Fuel System Cleanup and FGD/SCR work
+	BIG BEND 3	Apr 28	-	Jul 06	Main ST Blade R&R, LP L-0 Blade replace, BFP Turbine R&R, DCS Controls Upgrade, 5th and 6th Point Feedwater Heater R&R, FD Fan rating damp duct R&R, CWP repair, FGD Twr Piping
		Nov 30	-	Dec 09	Fuel System Cleanup and FGD/SCR work
	BIG BEND 4	Feb 16	-	Mar 01	Fuel System Cleanup and FGD/SCR work
		Nov 10	-	Nov 19	Fuel System Cleanup and FGD/SCR work
	POLK 1	Mar 03	-	Mar 22	Gasifier Outage
		Nov 03	-	Nov 09	Gasifier Outage
+	BAYSIDE 1	Feb 14	-	Apr 10	ST 1 Centerline, Valves, Condenser and Aux, HRSG Internal Inspect and repair, HRSG Control Valve Work, HRSG Drain Valve Work, High Energy Piping and Pipe Support Inspect, #1 Common Systems High Energy Piping Systems Inspect, CT High Energy Piping / Pipe support Adj and Re-alignments
		Nov 27	-	Dec 08	Fuel System Cleanup
+	BAYSIDE 2	Apr 15	-	Apr 29	Fuel System Cleanup
		Sep 26	-	Nov 20	ST 2 Centerline, Valves, Condenser and Aux, HRSG Internal Inspect and repair, HRSG Control Valve Work, HRSG Drain Valve Work, High Energy Piping and Pipe Support Inspect, #2 Common Systems High Energy Piping Systems Inspect, CT High Energy Piping / Pipe support Adj and Re-alignments

+ 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 2017 - DECEMBER 2017

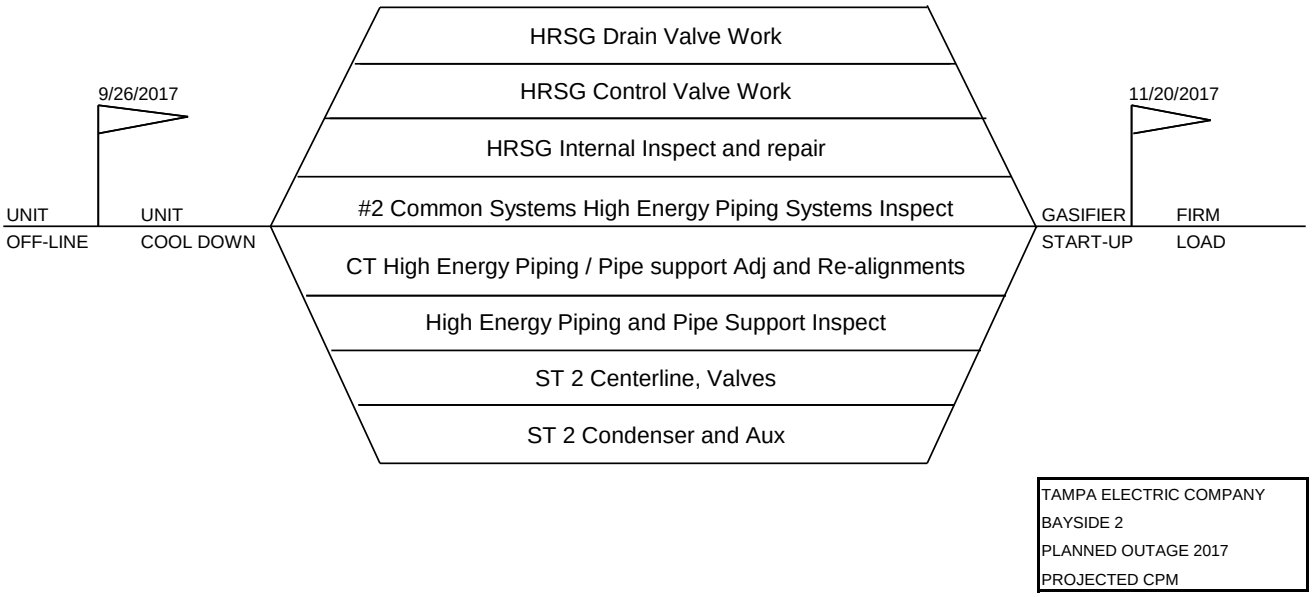


TAMPA ELECTRIC COMPANY
BIG BEND 3
PLANNED OUTAGE 2017
PROJECTED CPM

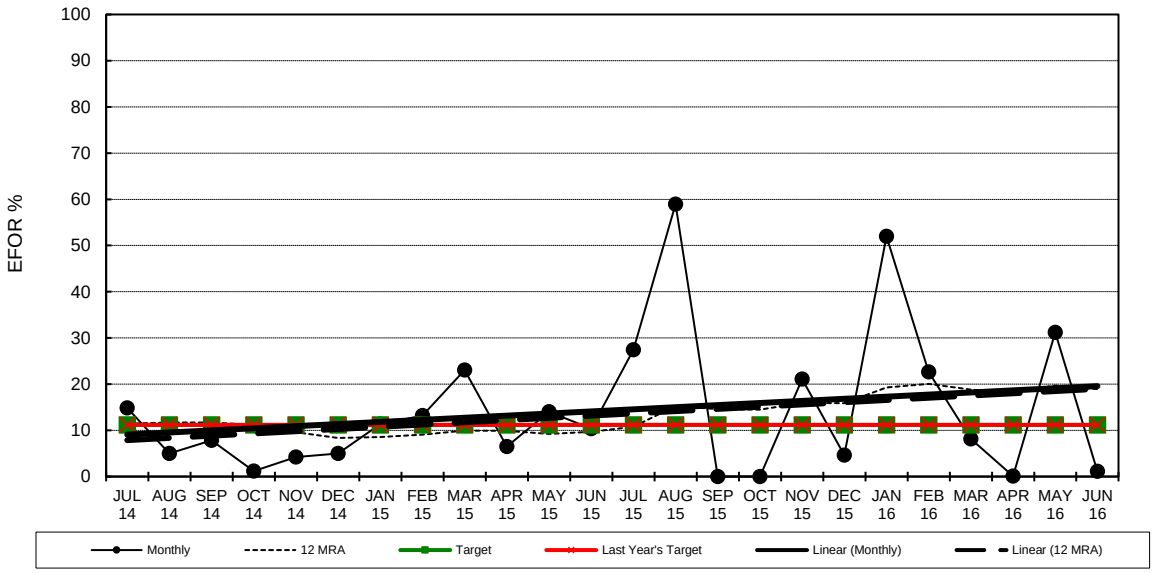


TAMPA ELECTRIC COMPANY
BAYSIDE 1
PLANNED OUTAGE 2017
PROJECTED CPM

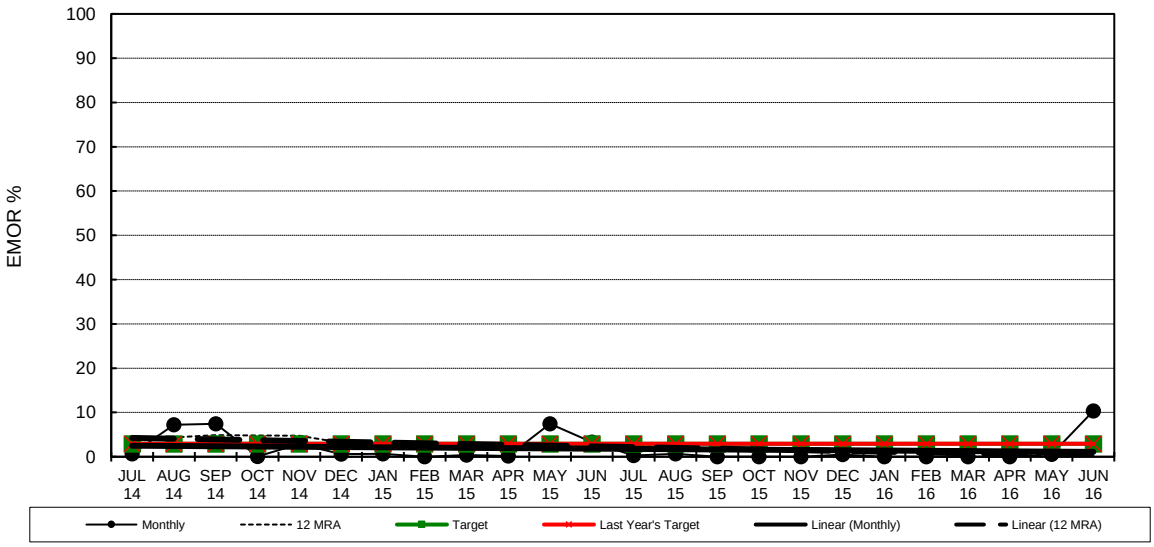
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2017 - DECEMBER 2017

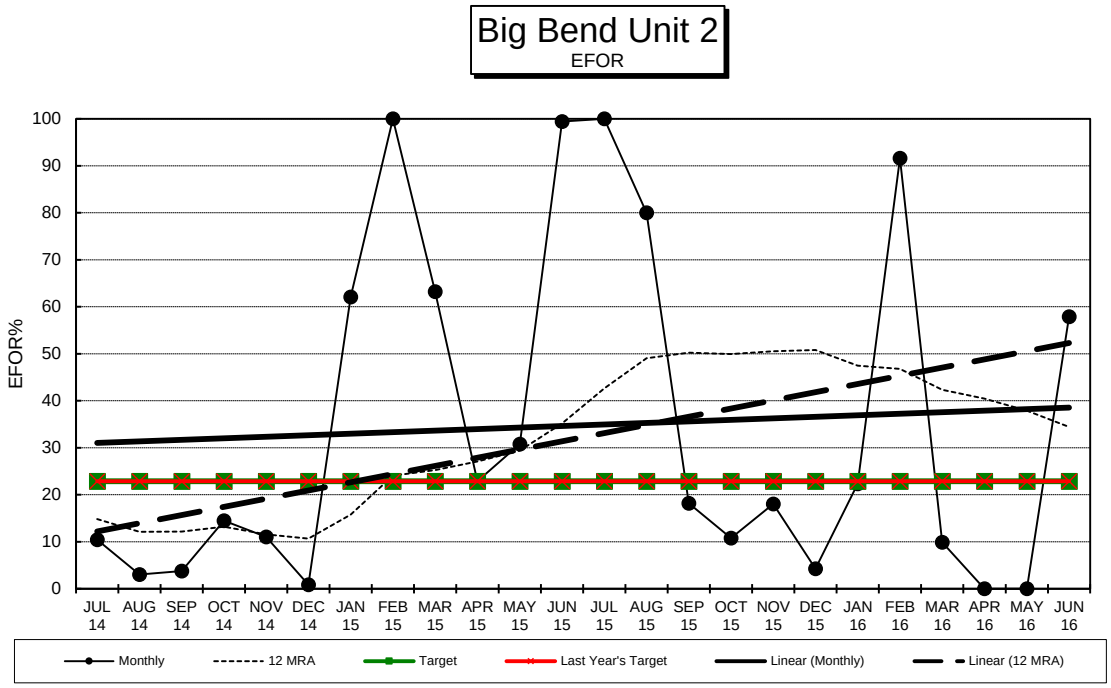


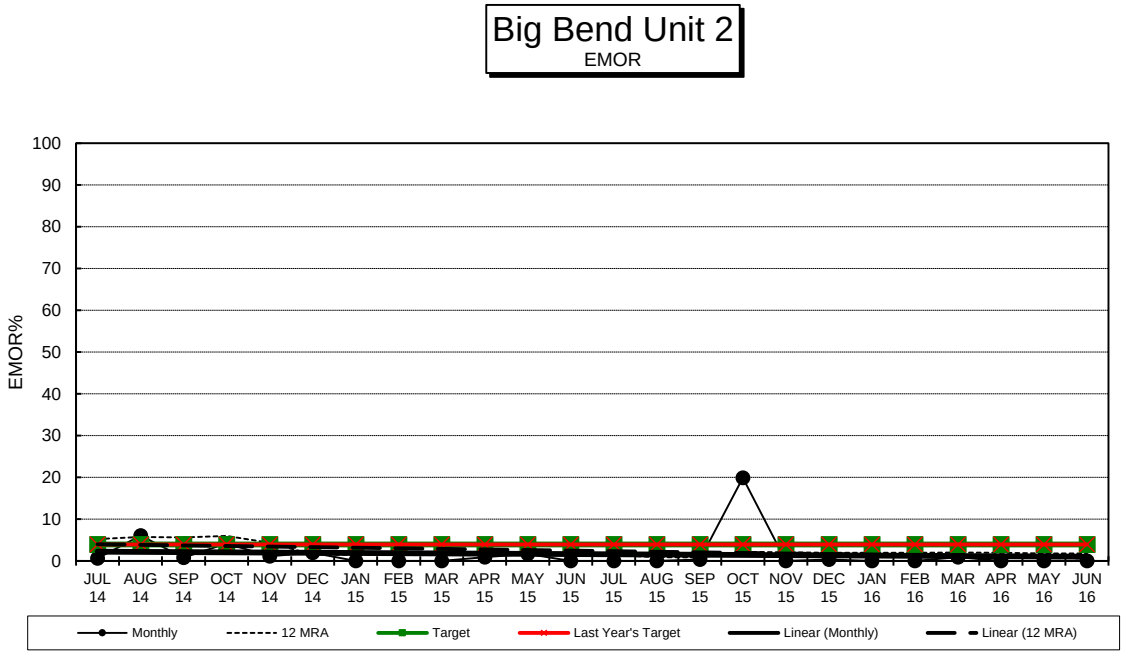
Big Bend Unit 1
EFOR

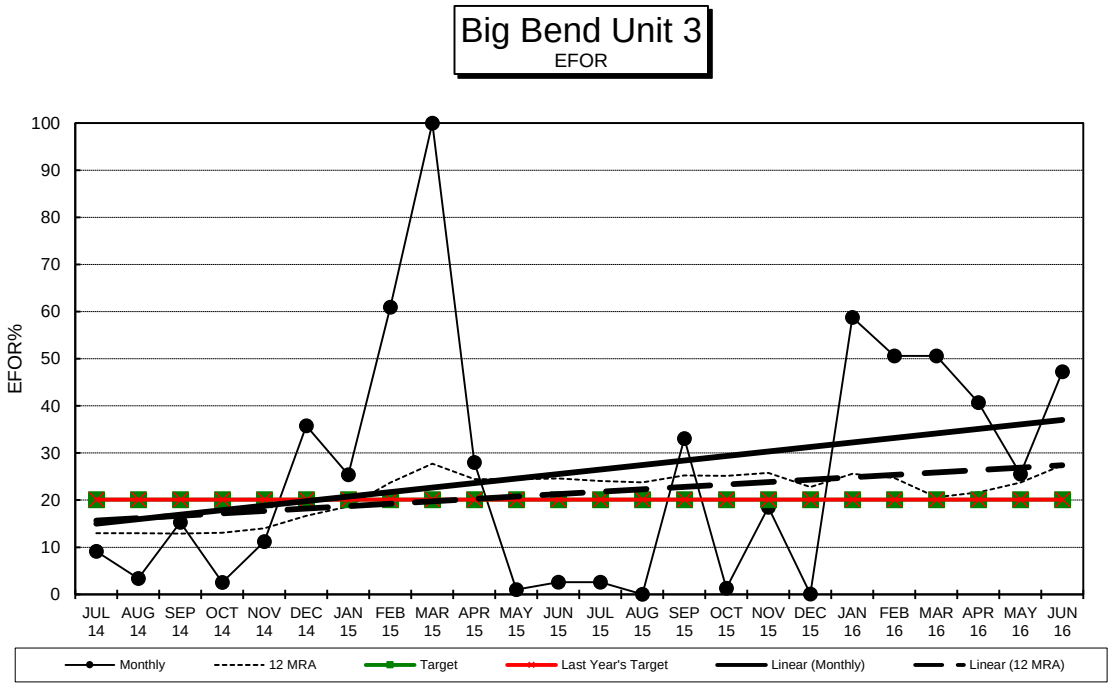


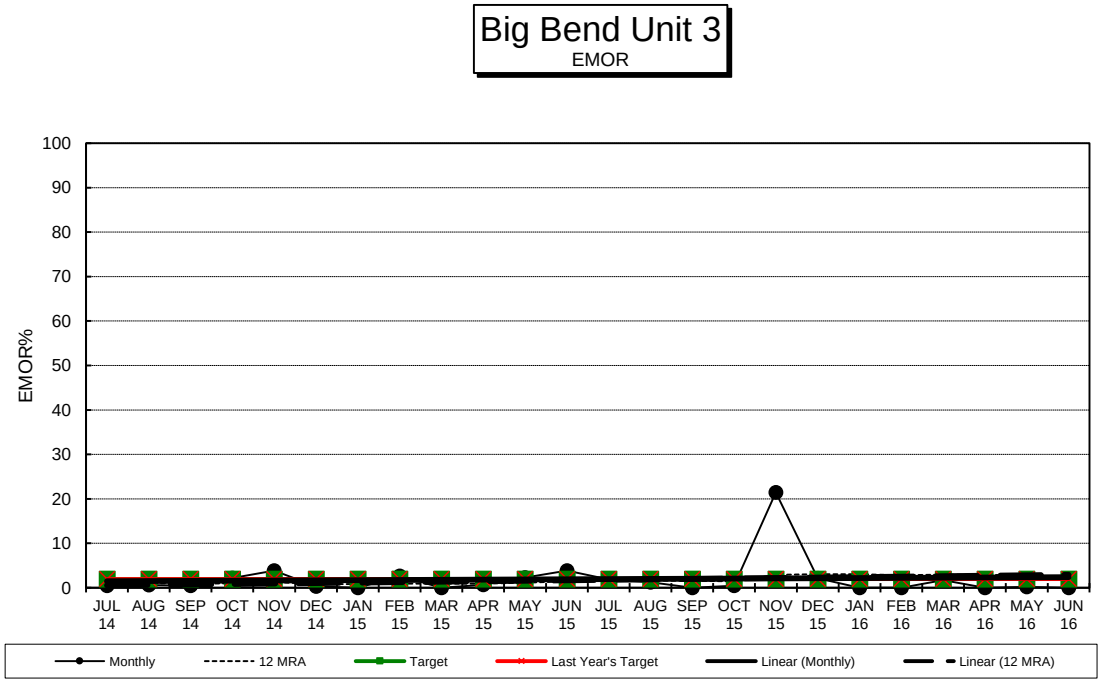
Big Bend Unit 1
EMOR

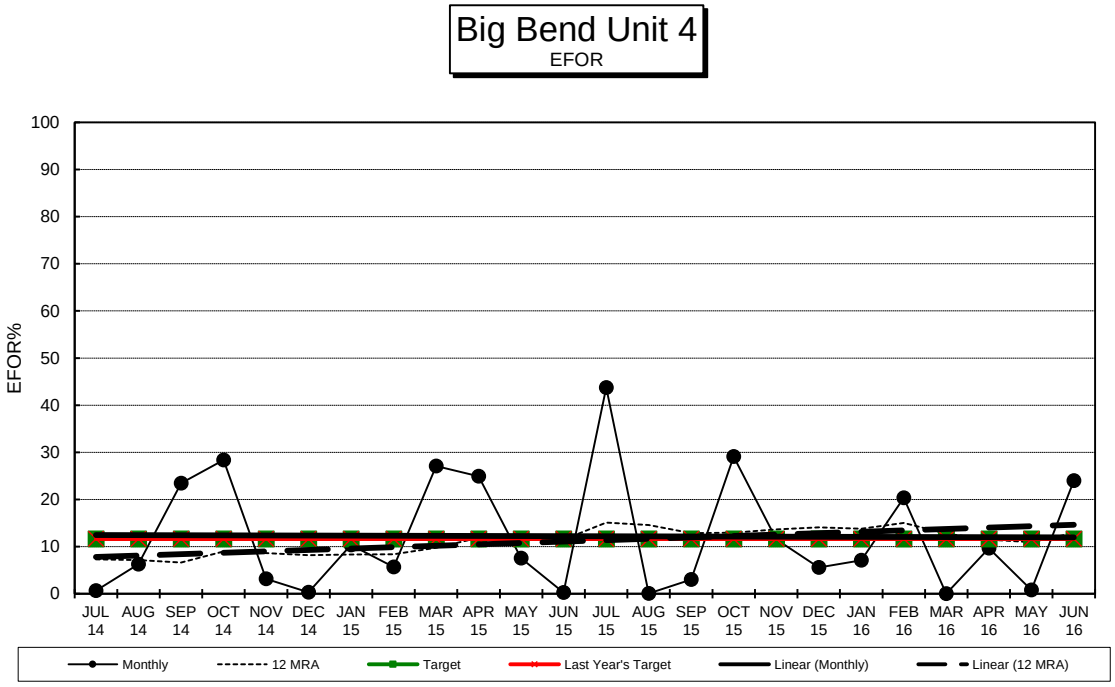


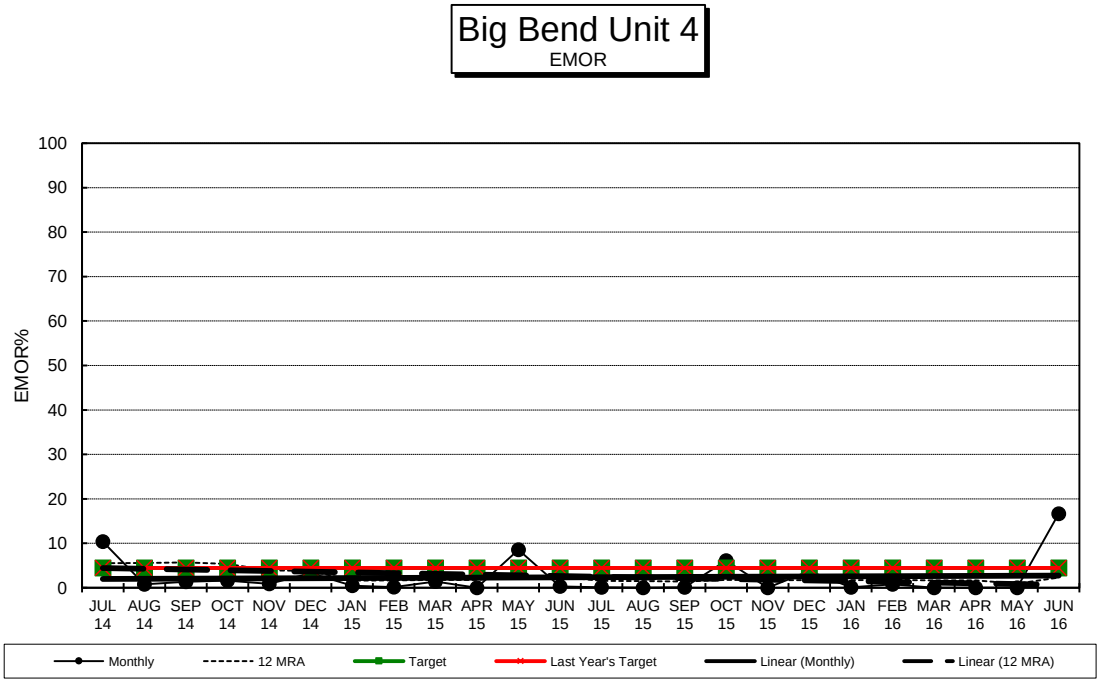

Big Bend Unit 2
EFOR
EFOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

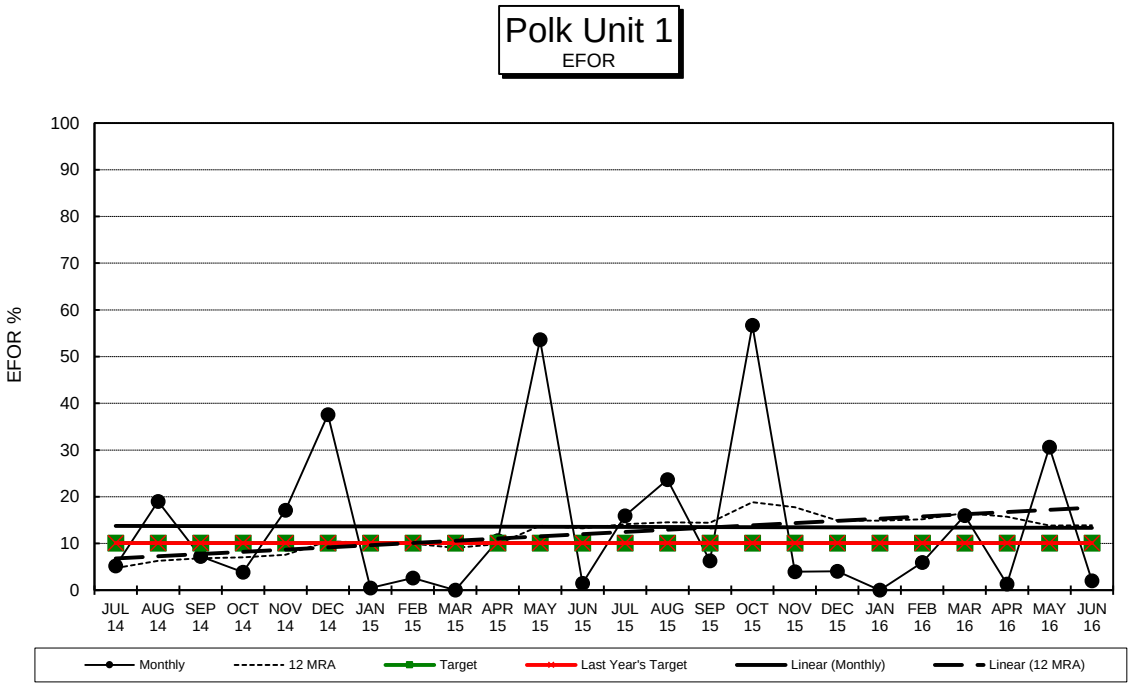

Big Bend Unit 2
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

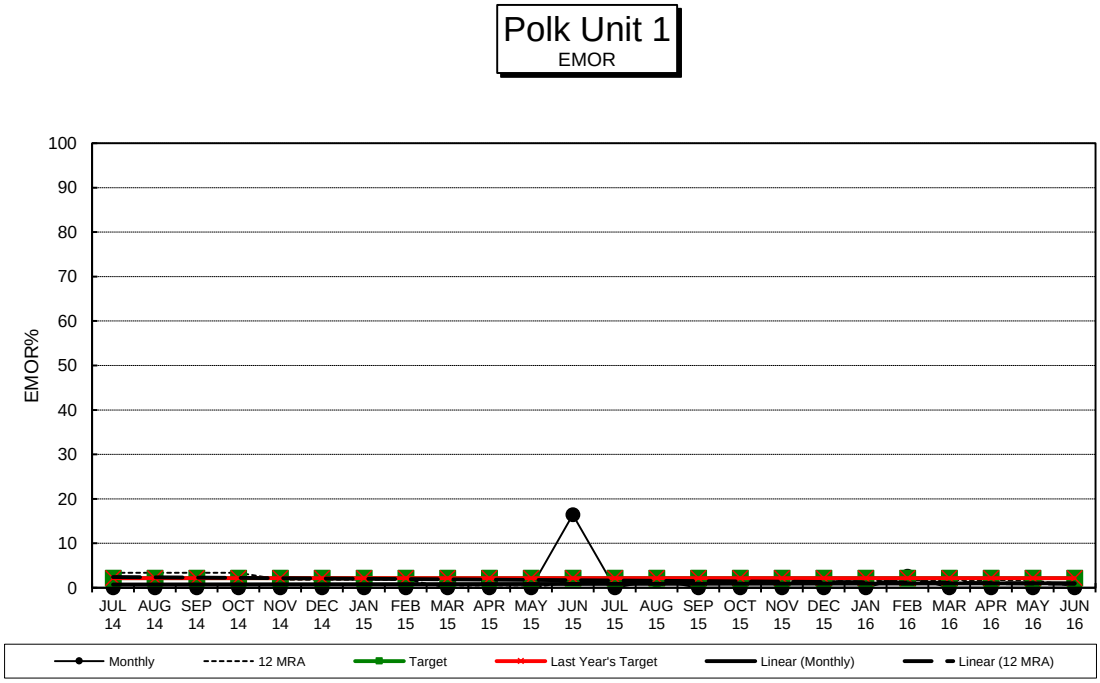

Big Bend Unit 3
EFOR
EFOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

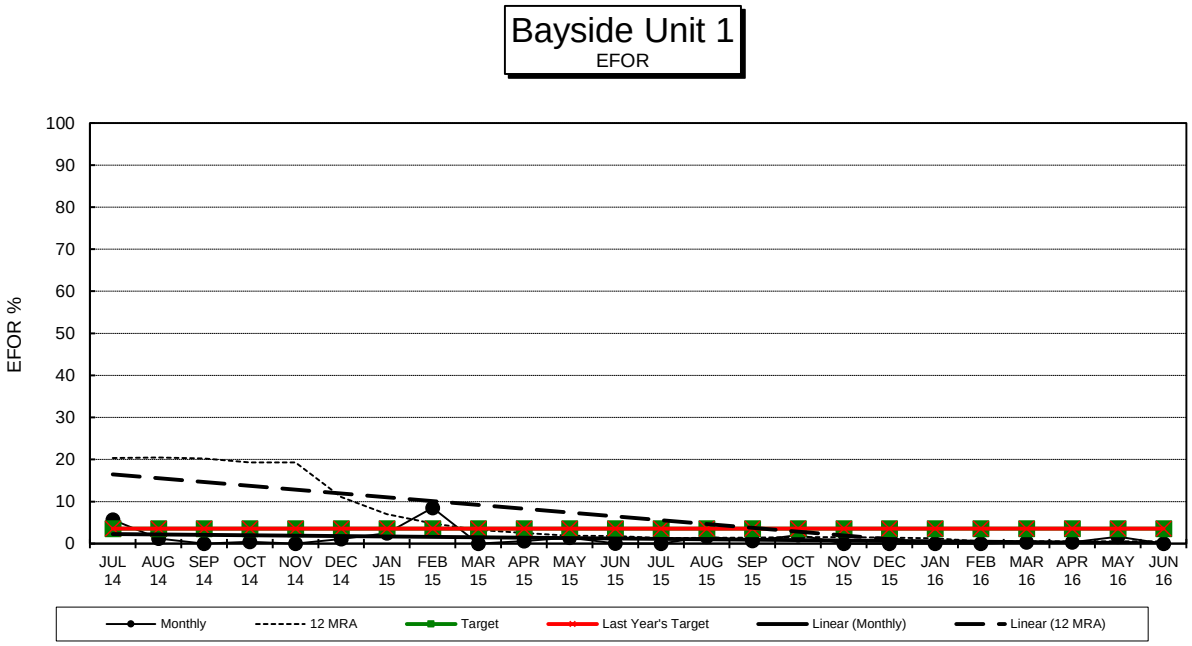

Big Bend Unit 3
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

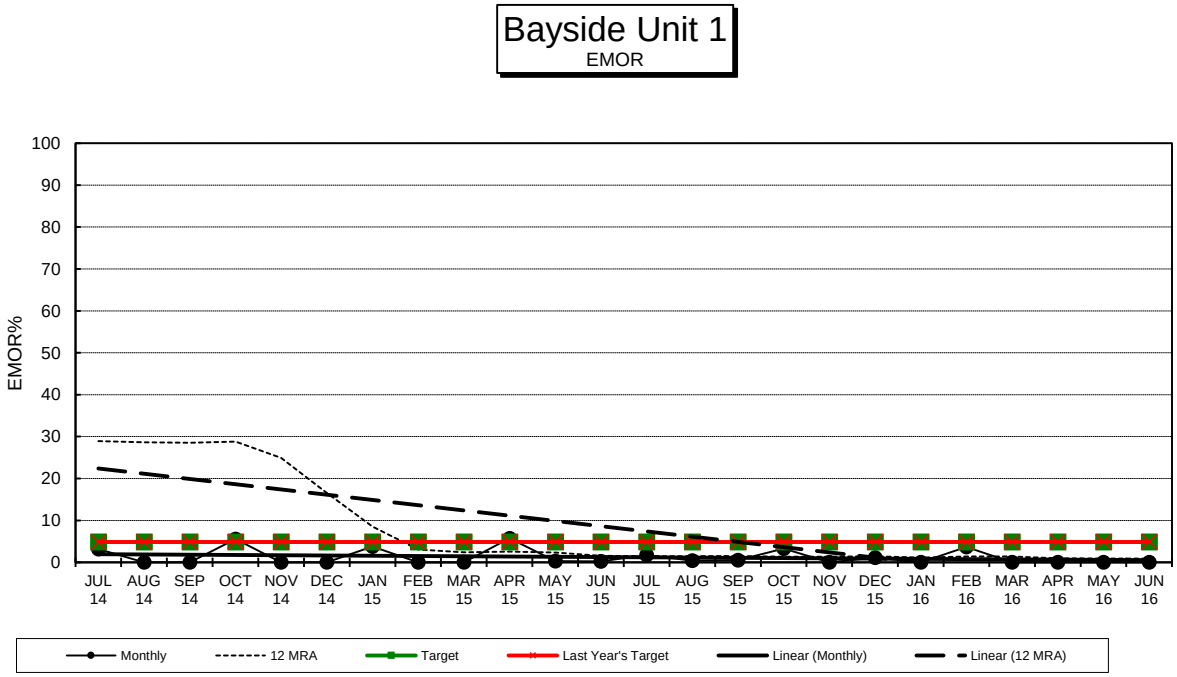

Big Bend Unit 4
EFOR
EFOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

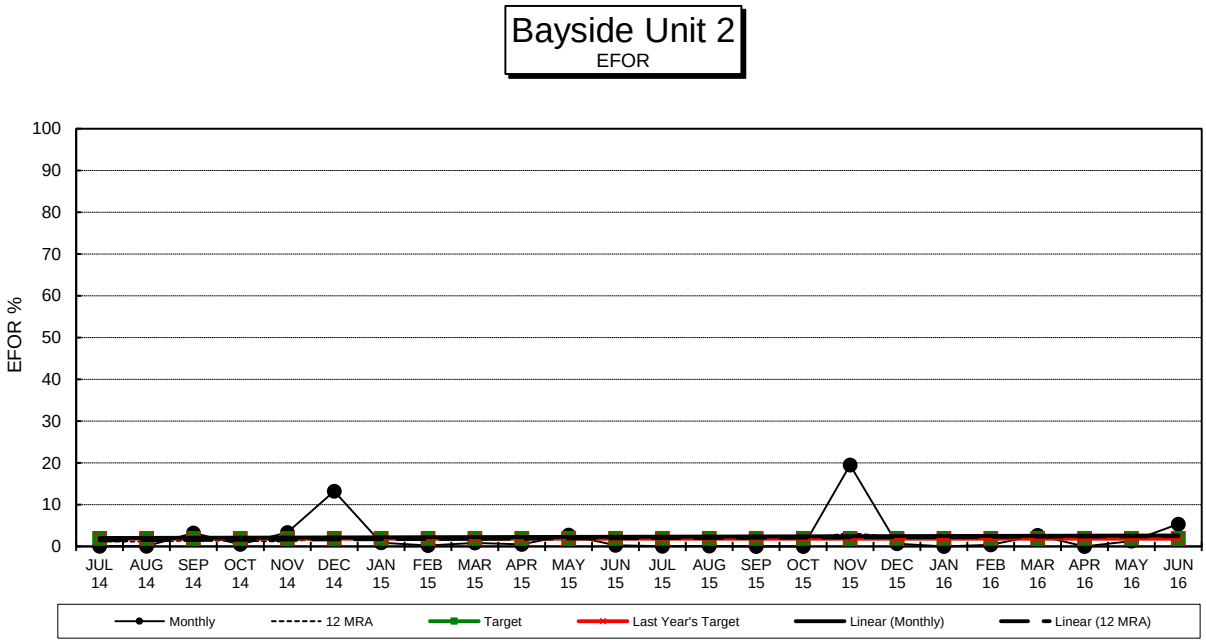

Big Bend Unit 4
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

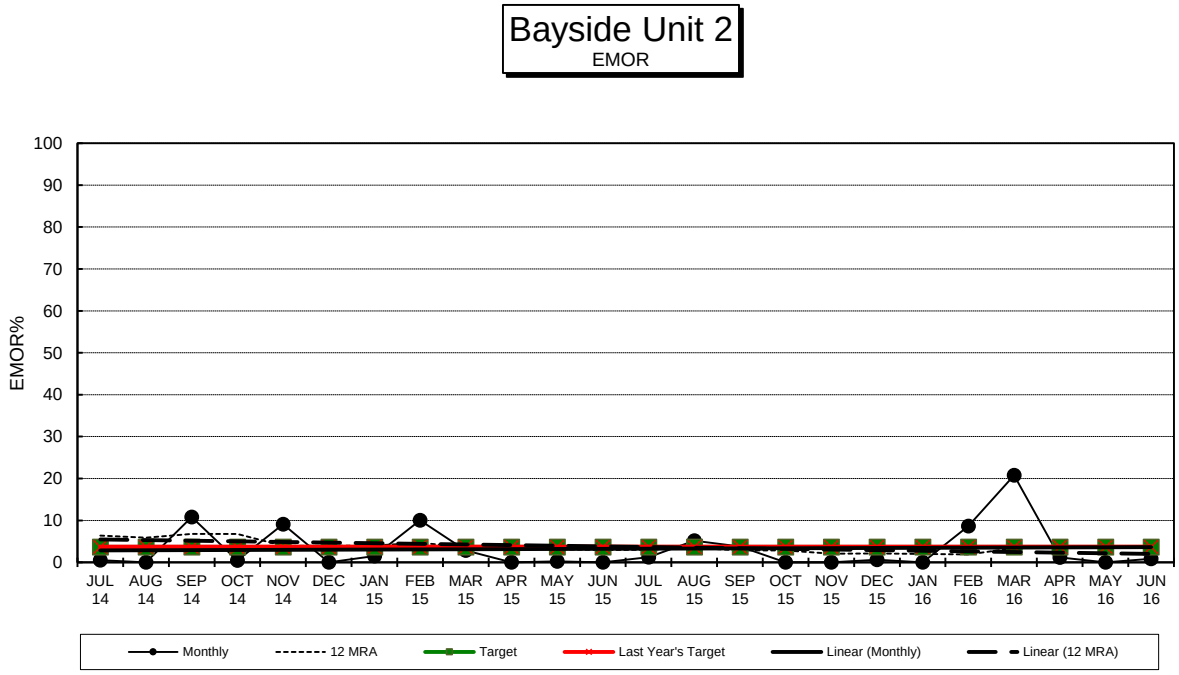

Polk Unit 1
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

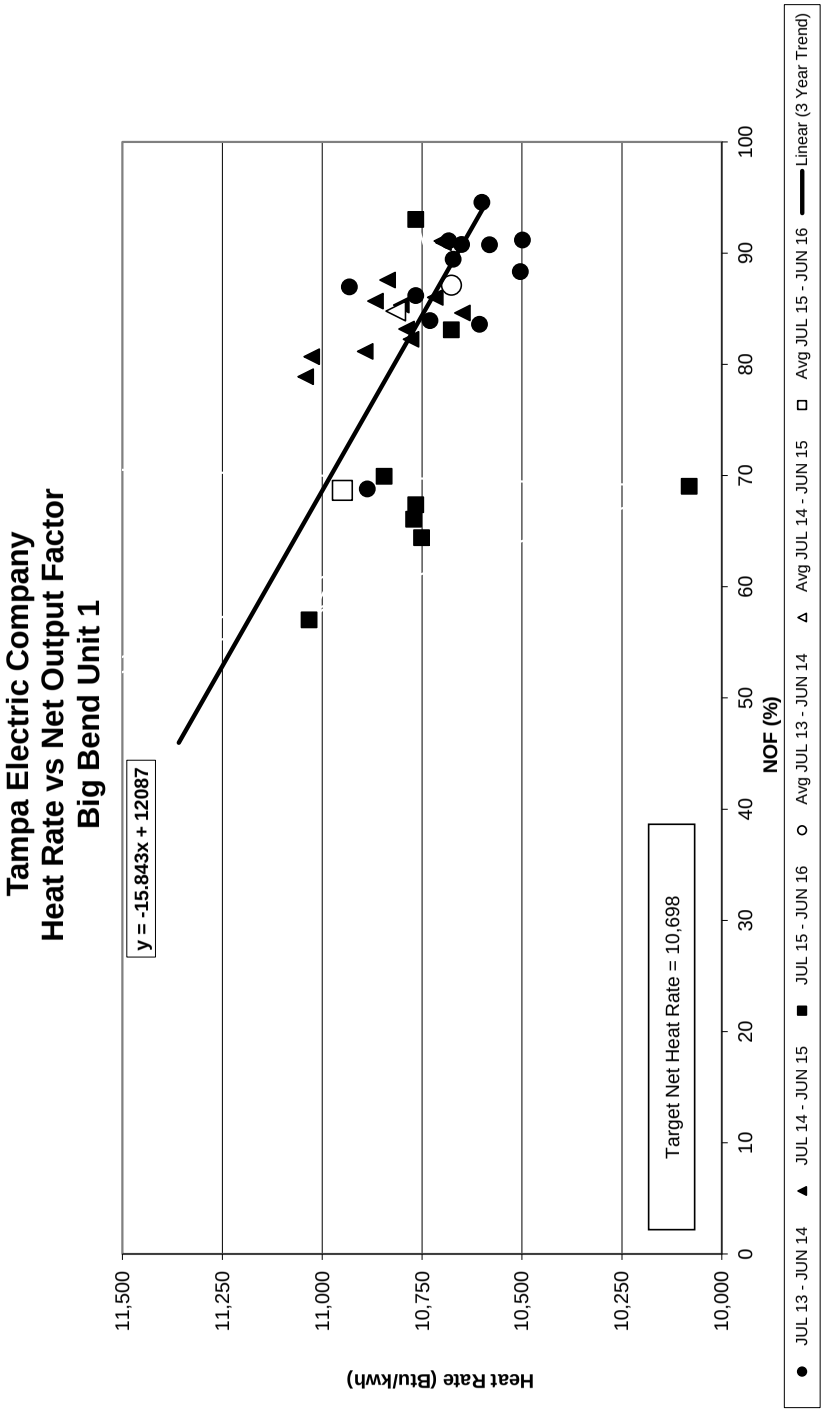

Polk Unit 1
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

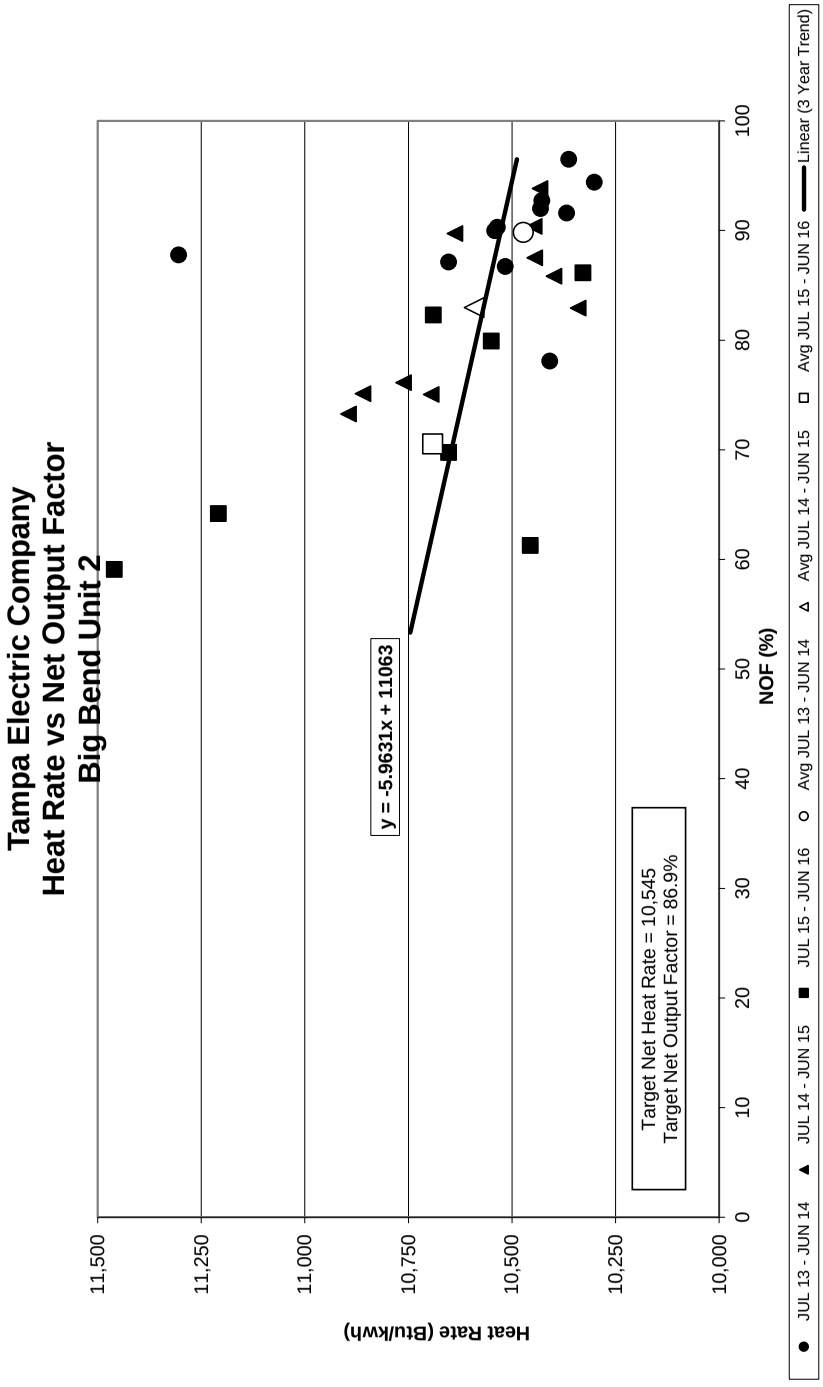

Bayside Unit 1
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

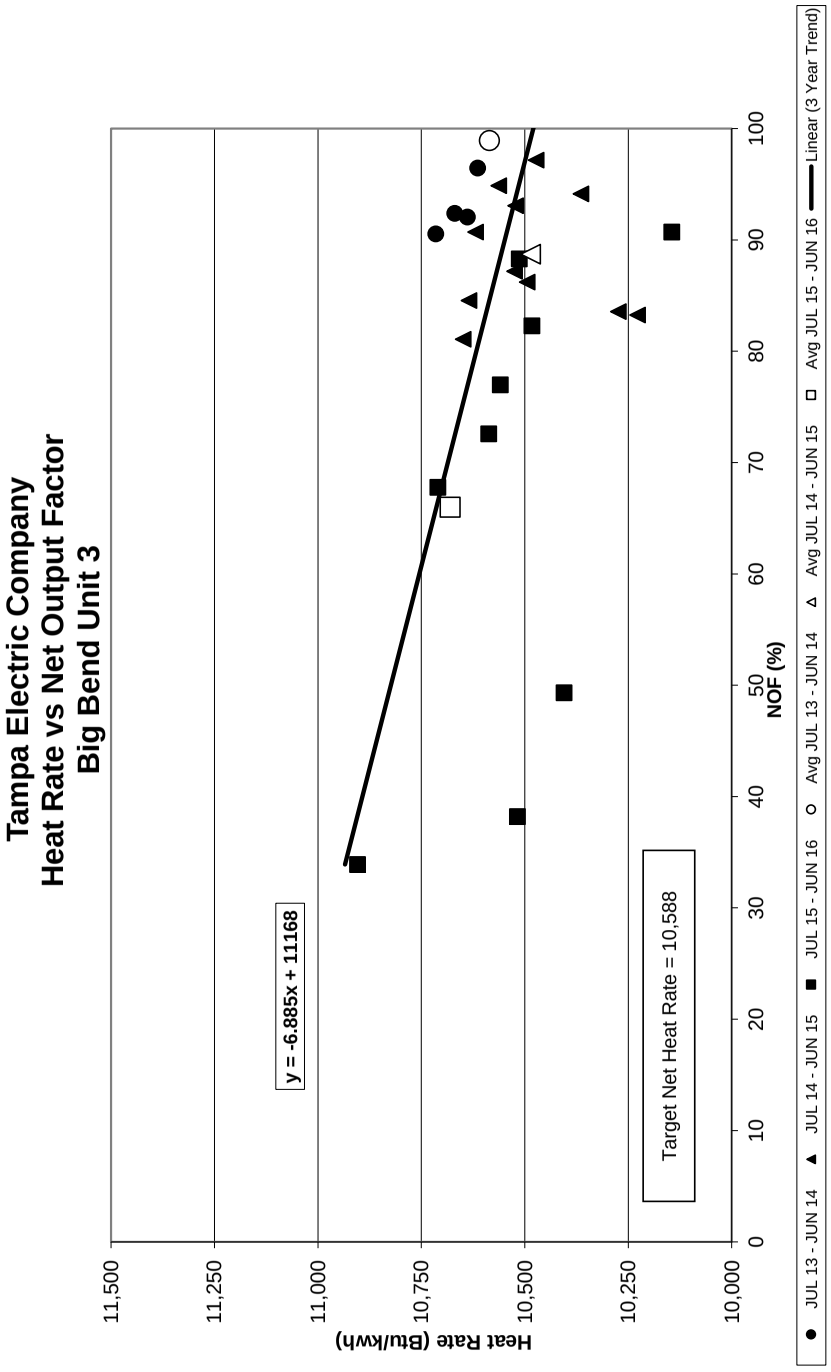

Bayside Unit 1
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

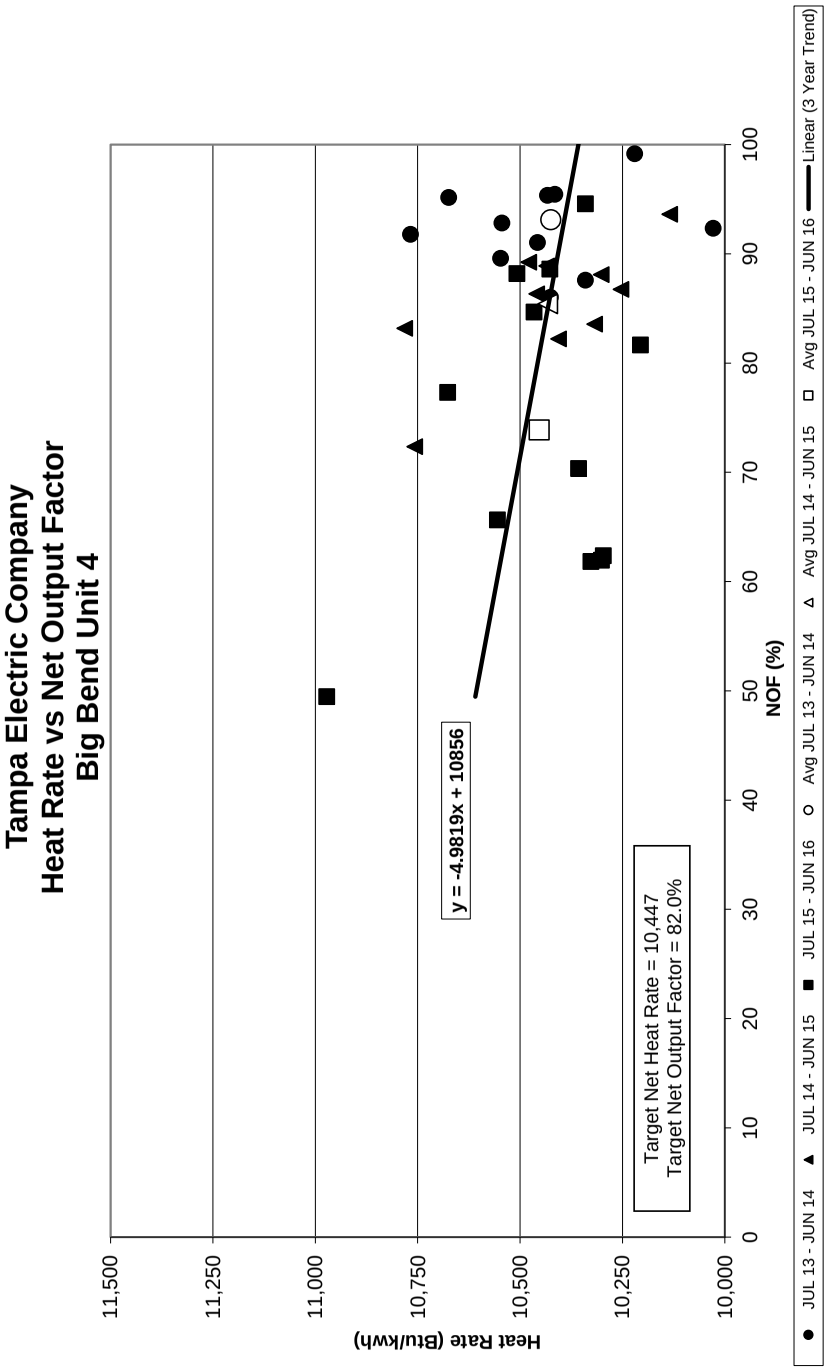

Bayside Unit 2
EFOR
EFOR %
100
90
80
70
60
50
40
30
20
10
0
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

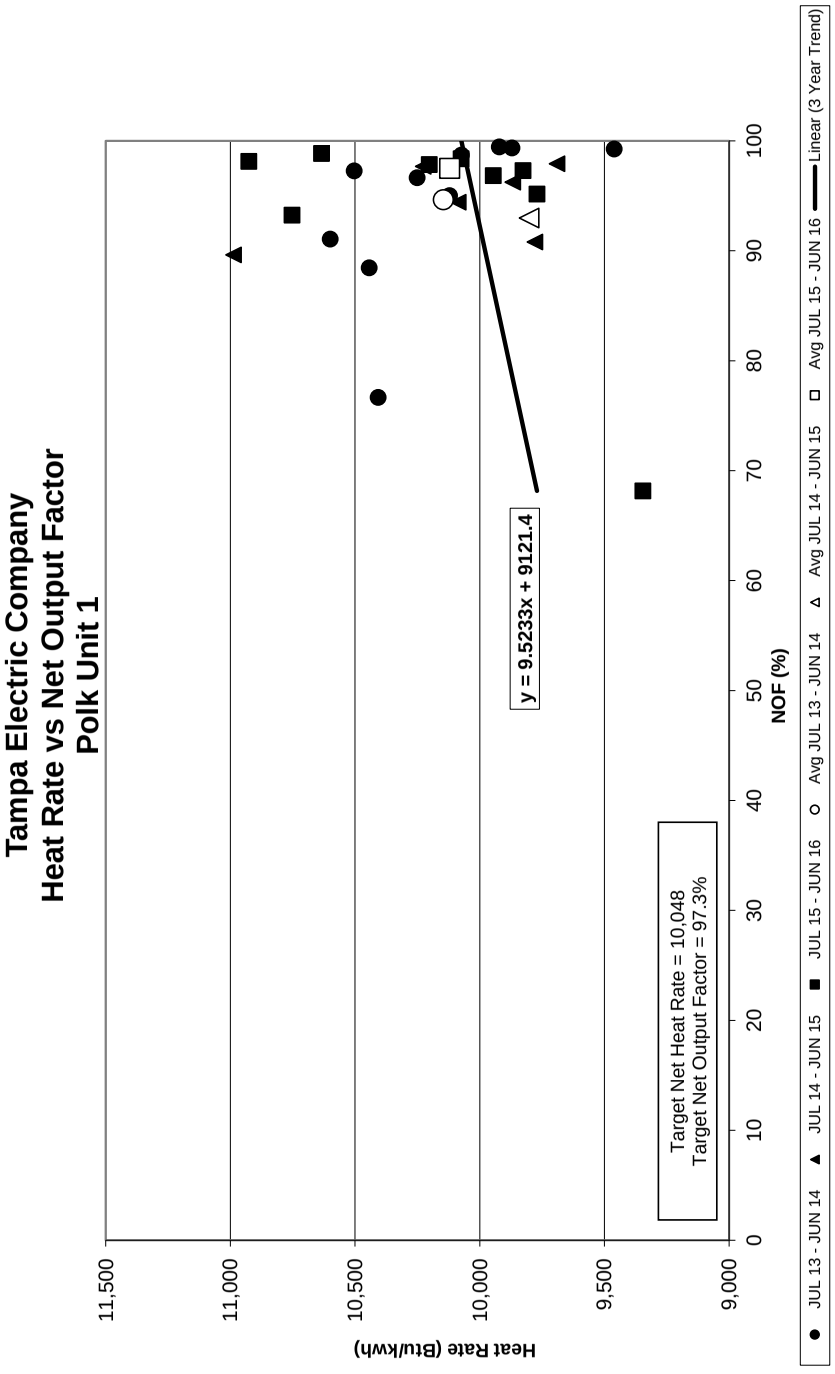

Bayside Unit 2
EMOR
EMOR%
100
90
80
70
60
50
40
30
20
10
0
JUL 14
AUG 14
SEP 14
OCT 14
NOV 14
DEC 14
JAN 15
FEB 15
MAR 15
APR 15
MAY 15
JUN 15
JUL 15
AUG 15
SEP 15
OCT 15
NOV 15
DEC 15
JAN 16
FEB 16
MAR 16
APR 16
MAY 16
JUN 16
Monthly
12 MRA
Target
Last Year's Target
Linear (Monthly)
Linear (12 MRA)

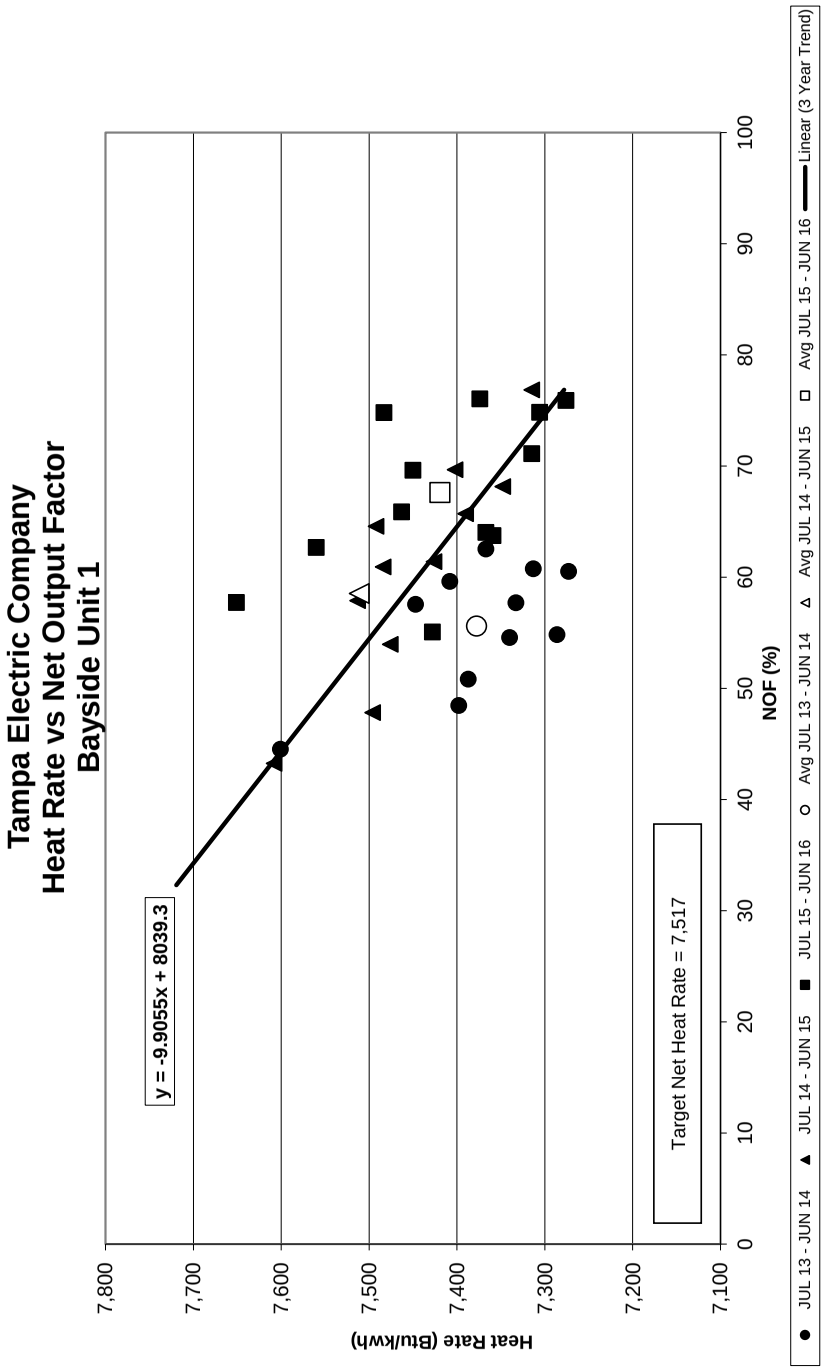

Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 1
y = -15.843x + 12087
Target Net Heat Rate = 10,698
Heat Rate (Btu/kwh)
NOF (%)
11,500
11,250
11,000
10,750
10,500
10,250
10,000
0
10
20
30
40
50
60
70
80
90
100
JUL 13 - JUN 14
JUL 14 - JUN 15
JUL 15 - JUN 16
Avg JUL 13 - JUN 14
Avg JUL 14 - JUN 15
Avg JUL 15 - JUN 16
Linear (3 Year Trend)

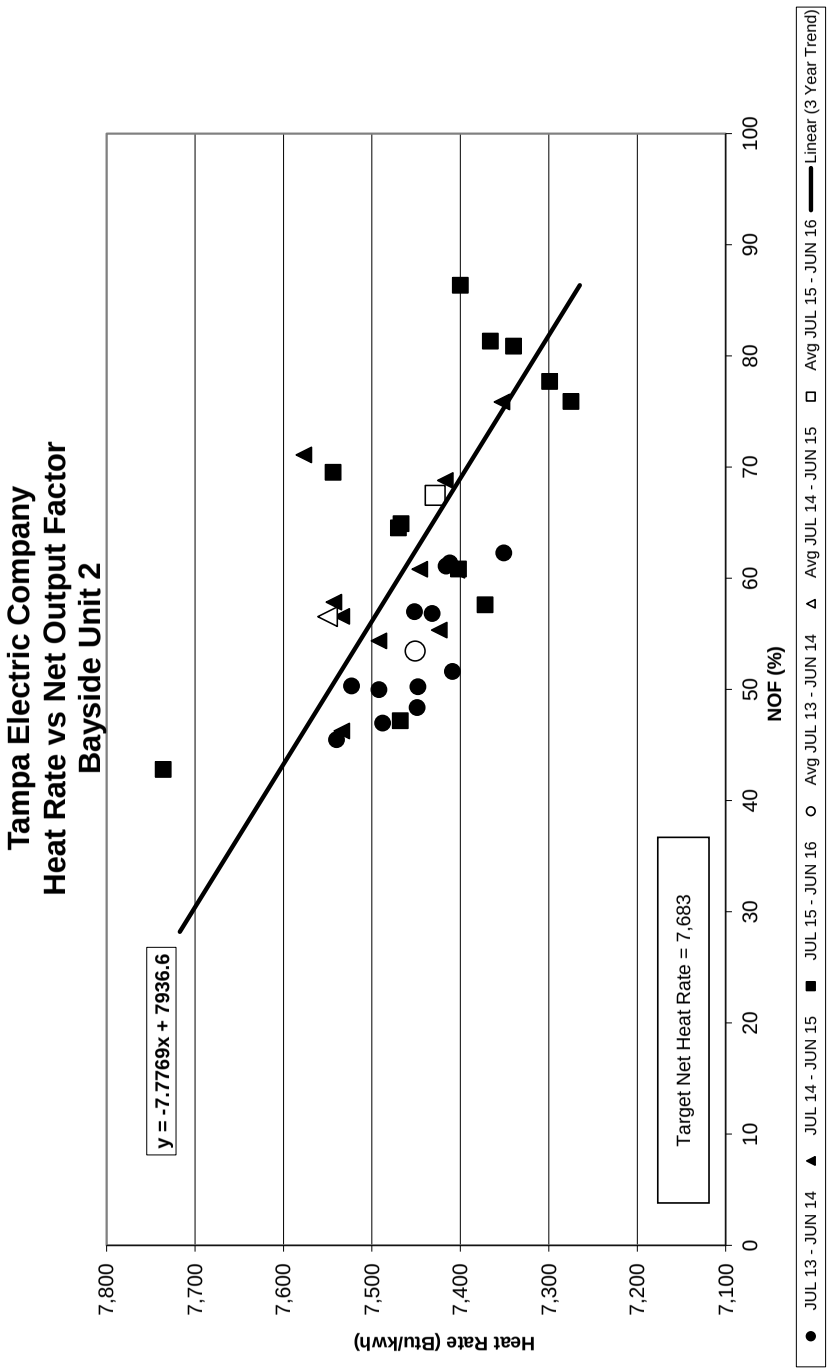

Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 2
y = -5.9631x + 11063
Target Net Heat Rate = 10,545
Target Net Output Factor = 86.9%
Heat Rate (Btu/kwh)
NOF (%)
11,500
11,250
11,000
10,750
10,500
10,250
10,000
0
10
20
30
40
50
60
70
80
90
100
JUL 13 - JUN 14
JUL 14 - JUN 15
JUL 15 - JUN 16
Avg JUL 13 - JUN 14
Avg JUL 14 - JUN 15
Avg JUL 15 - JUN 16
Linear (3 Year Trend)


Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 3
y = -6.885x + 11168
Target Net Heat Rate = 10,588
Heat Rate (Btu/kwh)
NOF (%)
11,500
11,250
11,000
10,750
10,500
10,250
10,000
0
10
20
30
40
50
60
70
80
90
100
JUL 13 - JUN 14
JUL 14 - JUN 15
JUL 15 - JUN 16
Avg JUL 13 - JUN 14
Avg JUL 14 - JUN 15
Avg JUL 15 - JUN 16
Linear (3 Year Trend)


Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit 4
Heat Rate (Btu/kwh)
NOF (%)
y = -4.9819x + 10856
Target Net Heat Rate = 10,447
Target Net Output Factor = 82.0%
JUL 13 - JUN 14
JUL 14 - JUN 15
JUL 15 - JUN 16
Avg JUL 13 - JUN 14
Avg JUL 14 - JUN 15
Avg JUL 15 - JUN 16
Linear (3 Year Trend)


Tampa Electric Company
Heat Rate vs Net Output Factor
Polk Unit 1
y = 9.5233x + 9121.4
Target Net Heat Rate = 10,048
Target Net Output Factor = 97.3%
Heat Rate (Btu/kwh)
NOF (%)
11,500
11,000
10,500
10,000
9,500
9,000
0
10
20
30
40
50
60
70
80
90
100
JUL 13 - JUN 14
JUL 14 - JUN 15
JUL 15 - JUN 16
Avg JUL 13 - JUN 14
Avg JUL 14 - JUN 15
Avg JUL 15 - JUN 16
Linear (3 Year Trend)


Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 1
y = -9.9055x + 8039.3
Target Net Heat Rate = 7,517
Heat Rate (Btu/kwh)
NOF (%)
7,800
7,700
7,600
7,500
7,400
7,300
7,200
7,100
0
10
20
30
40
50
60
70
80
90
100
JUL 13 - JUN 14
JUL 14 - JUN 15
JUL 15 - JUN 16
Avg JUL 13 - JUN 14
Avg JUL 14 - JUN 15
Avg JUL 15 - JUN 16
Linear (3 Year Trend)


Tampa Electric Company
Heat Rate vs Net Output Factor
Bayside Unit 2
y = -7.7769x + 7936.6
Target Net Heat Rate = 7,683
Heat Rate (Btu/kwh)
NOF (%)
7,800
7,700
7,600
7,500
7,400
7,300
7,200
7,100
0
10
20
30
40
50
60
70
80
90
100
JUL 13 - JUN 14
JUL 14 - JUN 15
JUL 15 - JUN 16
Avg JUL 13 - JUN 14
Avg JUL 14 - JUN 15
Avg JUL 15 - JUN 16
Linear (3 Year Trend)

TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2017 - DECEMBER 2017

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1		413	388
BIG BEND 2		413	388
BIG BEND 3		422	397
BIG BEND 4		472	439
POLK 1		290	220
BAYSIDE 1		740	731
BAYSIDE 2		979	968
	GPIF TOTAL	3,730	3,532
	SYSTEM TOTAL	**5,157**	**4,978**
	% OF SYSTEM TOTAL	**72.3%**	**70.9%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2017 - DECEMBER 2017

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		413	388
BIG BEND 2		413	388
BIG BEND 3		422	397
BIG BEND 4		472	439
BIG BEND CT4		59	58
	BIG BEND TOTAL	1,779	1,670
POLK 1		290	220
POLK 2		1,113	1,137
	POLK TOTAL	1,403	1,357
SOLAR		21	21
	SOLAR TOTAL	21	21
	SYSTEM TOTAL	**5,157**	**4,978**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2017 - DECEMBER 2017

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
POLK	2	5,957,150	30.30%	30.30%
BAYSIDE	1	2,208,770	11.23%	41.53%
BAYSIDE	2	2,103,790	10.70%	52.24%
BIG BEND	2	2,078,760	10.57%	62.81%
BIG BEND	4	1,946,620	9.90%	72.71%
BIG BEND	1	1,917,590	9.75%	82.46%
BIG BEND	3	1,822,110	9.27%	91.73%
POLK	1	1,555,680	7.91%	99.64%
SOLAR		36,390	0.19%	99.83%
BIG BEND CT	4	11,630	0.06%	99.89%
BAYSIDE	5	7,600	0.04%	99.93%
BAYSIDE	6	5,930	0.03%	99.96%
BAYSIDE	3	4,720	0.02%	99.98%
BAYSIDE	4	3,630	0.02%	100.00%
TOTAL GENERATION		19,660,370	100.00%	

GENERATION BY COAL UNITS: 9,320,760 MWH
% GENERATION BY COAL UNITS 47.41%

GENERATION BY NATURAL GAS UNITS: 10,303,220 MWH
% GENERATION BY NATURAL GAS UNITS: 52.41%

GENERATION BY SOLAR UNITS: 36,390 MWH
% GENERATION BY SOLAR UNIT 0.19%

GENERATION BY GPIF UNITS: 13,633,320 MWH
% GENERATION BY GPIF UNITS: 69.34%

* Polk 2 CC will be a new CC unit.

DOCKET NO. 160001-EI
GPIF 2017 PROJECTION FILING
EXHIBIT NO. BSB-2
DOCUMENT NO. 2

EXHIBIT TO THE TESTIMONY OF

BRIAN S. BUCKLEY

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS
JANUARY 2017 – DECEMBER 2017

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2017 - DECEMBER 2017

Unit	Availability			Net
	EAF	POF	EUOF	Heat Rate
Big Bend 1[1]	80.5	6.6	12.9	10,698
Big Bend 2[2]	69.6	6.6	23.8	10,545
Big Bend 3[3]	61.4	21.9	16.7	10,588
Big Bend 4[4]	79.1	6.6	14.3	10,447
Polk 1[5]	82.1	7.4	10.5	10,048
Bayside 1[6]	75.3	18.6	6.1	7,517
Bayside 2[7]	76.1	19.5	4.4	7,683

1 Original Sheet 8.401.17E, Page 14

2 Original Sheet 8.401.17E, Page 15

3 Original Sheet 8.401.17E, Page 16

4 Original Sheet 8.401.17E, Page 17

5 Original Sheet 8.401.17E, Page 18

6 Original Sheet 8.401.17E, Page 19

7 Original Sheet 8.401.17E, Page 20

Tampa Electric
2015 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 so as 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.

2015 Risk Management Activities
The company's activities in 2015 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 with the goal of minimizing fuel costs and price risk while maintaining reliability of supply. The company procured all of its 2015 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 48 percent of the electricity the company generated in 2015.

- 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.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 54
PARTY: TAMPA ELECTRIC COMPANY – (DIRECT)
DESCRIPTION: J. Brent Caldwell JBC-1

- Natural Gas Purchases

  In 2015, approximately 52 percent of the electricity Tampa Electric generated was produced using natural gas. Tampa Electric's risk management strategy continues to focus on supply reliability and price volatility reduction. The components critical to the success of the natural gas purchasing strategy are as follows:

  - Execution of the natural gas hedge plan approved by the Risk Authorizing Committee;
  - Maintaining liquidity by contracting with numerous qualified counterparties;
  - Time horizon for natural gas hedging activity that allows the company to hedge natural gas prices into the future;
  - Maintaining a minimum and maximum hedge volume percentage by month into the future;
  - 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 Hedging 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. Therefore, Tampa Electric continued to use financial instruments to hedge the price of a portion of the natural gas consumed in 2015 to reduce customers' exposure to the volatility of natural gas prices. Tampa Electric used financial floating-price-to-fixed-price swaps to hedge natural gas prices. The costs associated with these instruments are embedded in the price of the instruments and are included in the fuel commodity costs reported by the company. The hedges are described in the following table.

Tampa Electric Company
Natural Gas Hedging Activities
January 1, 2015 through December 31, 2015

	Type of Hedge	Mark-to-Market Saving/(Loss)	Hedged Volume (MMBTU)	Consumption (MMBTU)	Percent Hedged	Budget Price	Hedge Price	Settle Price
Jan-15	Swaps	($2,576,655)	[redacted]	4,459,415	[redacted]	[redacted]	[redacted]	$3.189
Feb-15	Swaps	($3,450,145)	[redacted]	4,073,535	[redacted]	[redacted]	[redacted]	$2.866
Mar-15	Swaps	($3,338,845)	[redacted]	6,272,889	[redacted]	[redacted]	[redacted]	$2.894
Apr-15	Swaps	($3,428,830)	[redacted]	5,842,268	[redacted]	[redacted]	[redacted]	$2.590
May-15	Swaps	($4,357,580)	[redacted]	7,263,430	[redacted]	[redacted]	[redacted]	$2.517
Jun-15	Swaps	($3,356,285)	[redacted]	8,097,636	[redacted]	[redacted]	[redacted]	$2.815
Jul-15	Swaps	($3,627,895)	[redacted]	8,092,380	[redacted]	[redacted]	[redacted]	$2.773
Aug-15	Swaps	($2,610,980)	[redacted]	8,045,798	[redacted]	[redacted]	[redacted]	$2.886
Sep-15	Swaps	($3,571,100)	[redacted]	7,453,216	[redacted]	[redacted]	[redacted]	$2.638
Oct-15	Swaps	($3,488,100)	[redacted]	6,996,753	[redacted]	[redacted]	[redacted]	$2.563
Nov-15	Swaps	($3,288,730)	[redacted]	5,773,557	[redacted]	[redacted]	[redacted]	$2.033
Dec-15	Swaps	($2,747,180)	[redacted]	4,259,752	[redacted]	[redacted]	[redacted]	$2.206
Total		**($39,842,325)**	[redacted]	**76,630,630**	[redacted]			

Consistent with Tampa Electric's non-speculative risk management plan objective, Tampa Electric's natural gas hedging plan provided price stability and certainty during 2015. For 2015, the calendar year net position for natural gas hedges was higher than the closing price of natural gas, resulting in a mark-to-market net loss of $39.8 million. Natural gas prices dropped significantly in 2015 due to an abundance of natural gas production and nearly full storage at the end of the summer injection season.

Tampa Electric maintains natural gas storage capacity of 1,500,000 MMBtu in order 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 a net loss of approximately $39.8 million in 2015; more importantly, Tampa Electric was

successful in reducing price uncertainty and maintaining fuel supply reliability for customers for both its physical and financial hedges.

2015 Market Pricing

Tampa Electric provides a comparison of 2015 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 specific enough to always 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 2015 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	Market Indicator Source	Note
Knight Hawk Coal LLC	[redacted]	$3.39	[redacted]	Gen 2014-01 (RFP issued 11/5/13)	1
Glencore Ltd.		$3.60		Gen- 2015-01-LS (email issued April 2014)	1
Alliance Coal (Warrior) LLC.		$3.39		Gen 2014-01 (RFP issued 11/5/13)	1
COALSALES LLC		$3.50		Gen 2015-03 (email issued Sept 2014)	1
CMC - Coal Marketing Company LTD.		$2.65		GEN-2016-02 (Phone solicitation May 2015)	1
Valero Marketing and Supply Company		$2.78		Gen 2015-04-PC (phone solicitation for 2015 Petcoke supply Sept 2014)	1,2
Valero Marketing and Supply Company		$2.78		Gen 2015-04-PC (phone solicitation for 2015 Petcoke supply Sept 2014)	1,2
Armstrong Coal Company Inc.		$3.30		Gen 2015-02 (email issued 6/10/14)	1
Trafigura AG Branch Office Stamford		$3.30		Gen 2015-02 (email issued 6/10/14)	1

Tampa Electric
Coal Contract to Market Indicator Price Comparisons

Supplier	Contract ($ / MMBtu)	Market Indicator ($ / MMBtu)	Difference	Market Indicator Source	Note
Trafigura AG Branch Office Stamford	[redacted]	$3.50	[redacted]	Gen 2015-03 (email issued Sept 2014)	1
Trafigura AG Branch Office Stamford		$2.88		Spot Purchase Q1-2, 2015 - Indices analysis/ Coal Daily 10/10/14 - Coaldesk 10/09/14	3
Consol Pennsylvania Coal Company LLC		$3.65		Gen 2014-01 (RFP issued 11/5/13) - Indices analysis	1,7
Consol Pennsylvania Coal Company LLC		$3.65		Gen 2014-01 (RFP issued 11/5/13) - Indices analysis	1,7
Consol Pennsylvania Coal Company LLC		$2.81		Spot Vessel Tons - Indices analysis/ Coal Daily - Coaldesk 4/15/15	4
Consol Pennsylvania Coal Company LLC		$3.12		Spot Rail Tons - Indices analysis/ Coal Daily - Coaldesk 5/1/15	5
White Oak Resources LLC		$2.83		Coaldesk (formally ICAP) / Argus Coal Daily 1/15/15 - 1/30/15	6
White Oak Resources LLC		$2.82		Coaldesk (formally ICAP) / Argus Coal Daily 11/19/14 - 11/21/14	8
Vitol, Inc.		$2.83		Coaldesk (formally ICAP) / Argus Coal Daily 11/19/14 - 11/21/14	8
Peabody Coal Trade LLC		$2.85		Argus Coal Daily, FOB Vessel Now Orleans, Hampton Rds, 3/6/2015	9
Koch Carbon LLC		$1.98		Argus/Pace Petroleum Coke Indexes (June 2015)	10
Koch Carbon LLC		$1.03		Argus/Pace Petroleum Coke Indexes (October 2015)	11

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. Market Indicator price is the average price submitted of all acceptable petcoke bids.
3. Coal Pricing based on average of two Indices. Argus 11,500 5.0lb SO_2, ICAP 11,500 5.2 Lb SO_2 (10/10/2014).
4. Coal Pricing based on average of two Indices, Coal Daily Atlantic Basin, US East Coast, FOB Hampton Rd 12,000 <1%, Coaldesk API 2 (4/15/15).
5. Coal Pricing based on average of two Indices. Argus Pittsburg Seam 13,000 3.50lb SO_2, Coaldesk MGA Rail 12,900 4.2 Lb SO_2 (5/1/15).
6. Index based purchase, pricing based on average of two Indices, Coaldesk (formally ICAP) / Argus Coal Daily (1/15/15 - 1/30/15).
7. Indicative pricing based on Argus Coal Daily and ICAP NAPP pricing (11/8/2013).
8. Index based purchase, pricing based on average of two Indices. Argus 11,800 4.5.0lb SO_2, Coaldesk, LLC 11,800 4.5 Lb SO_2 (11/19/14-11/21/14).
9. Index based purchase, pricing based on average of two Indices. FOB Vessel New Orleans and Hampton Rd, (3/6/2015).
10. Index based purchase, pricing based on average of two Indices. Argus and Pace Petroleum Coke Indexes (June 2015).
11. Index based purchase, pricing based on average of two Indices. Argus and Pace Petroleum Coke Indexes (October 2015).

- 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, 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 and for Big Bend 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.

TAMPA ELECTRIC COMPANY
FUEL PROCUREMENT AND WHOLESALE POWER PURCHASES
RISK MANAGEMENT PLAN
2017

Introduction

Tampa Electric serves its retail customers' electricity needs through a portfolio of generation and wholesale purchases. Tampa Electric's generation fuel mix is primarily a blend of coal and natural gas. While fuel mix diversity enhances long-term reliability, the reliance on natural gas can potentially increase variation in fuel prices. The company's risk management activities reduce the impact of price uncertainty and volatility to the Fuel and Purchased Power Cost Recovery Clause.

I. Qualitative and Quantitative Risk Management Objectives

A. Qualitative objectives

Tampa Electric's goals in managing risks associated with fuel or power purchases are focused on minimizing supply risk to ensure reliability of electric service to its customers at a reasonable price. To the extent price risk can be reduced without compromising supply reliability or imposing unnecessary costs on customers, Tampa Electric is committed to executing strategies to accomplish its risk management goals.

B. Quantitative objectives

Tampa Electric's quantitative objective is to prudently manage its fuel and wholesale energy procurement activities to minimize the variance from projected expenditures while taking advantage of cost-saving opportunities that do not result in increased supply risk. Tampa Electric has established a portfolio of fuel and purchased power products with creditworthy counterparties for known volumes and prices.

II. Oversight & Reporting of Fuel Procurement Activities

The company provides fuel and wholesale energy procurement activities with independent and unavoidable oversight.

A. The TECO Energy Board of Directors established an Energy Risk Management Policy ("Risk Policy"). This policy governs all energy commodities transacting activities at each of TECO Energy's operating units. The scope of this policy includes:

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 55
PARTY: TAMPA ELECTRIC COMPANY – (DIRECT)
DESCRIPTION: J. Brent Caldwell JBC-2

- Roles and responsibilities of various persons and functions with respect to risk management
- Authorized transacting activity
- Risk limits
- Valuation and data management
- Credit risk management
- Reporting
- Compliance and enforcement

B. The Risk Policy established the Risk Advisory Committee ("RAC"). The responsibilities of the RAC include the following activities:

- Reviewing the Risk Management Policy periodically and recommending changes and enhancements for approval by the Board of Directors ("Board").
- Reviewing corporate risk limits for recommendation to the Board.
- Establishing the quantitative limits for operating companies within Board approved corporate risk limits. The RAC may, at its discretion, delegate approval of sub-limits to operating company management.
- Approving parameters for counterparty credit limits and the allocation of limits among the operating companies.
- Establishing guidelines for risk management and measurement.
- Overseeing and reviewing the risk management process and infrastructure.
- Reviewing and approving transacting strategies proposed by the operating companies.
- Understanding and approving methodologies used for valuation and risk measurement.
- Reviewing and approving corporate and operating company risk limits.
- Establishing credit underwriting standards, and monitoring credit risk-taking activities and related exposures.
- Reviewing risk reports, including portfolio risk summaries and profitability and performance summaries.
- Enacting, maintaining, and enforcing limit violation and trader misconduct policies.
- Taking appropriate courses of action when the risk position of a transacting group has exceeded or is approaching the established limits.
- Reviewing and approving new risk management products.
- Presenting periodic reports to the Board or its committees.

C. TECO Energy established a corporate risk management function ("middle office"), which is overseen by the Director of Independent Risk Oversight.

D. Tampa Electric established additional oversight or control mechanisms to ensure compliance with policies and procedures. The following practices provide checks and balances on fuel and purchased power procurement activities.

- Fuel and wholesale energy procurement activities are conducted in accordance with company guidelines, including review by the operating stations and other management.
- All agreements are formalized in a written contract that is reviewed by legal counsel.
- The contracts are reviewed by the Director, Independent Risk Oversight of TECO Energy's Energy Risk Management Department for potential credit risks and incorporation of appropriate credit protection.
- The company maintains approval authority restrictions based on term and value of the transaction.
- Payments of invoices under each contract are settled and approved by an independent department.
- Each transaction is eligible for review by outside, internal and regulatory auditors.
- Information systems provide transaction authority control, credit monitoring, mark-to-market and value-at-risk analysis and other key controls.

E. In accordance with the Risk Policy, Tampa Electric established commodity specific transaction limits for commodity transactions.

- The Risk Authorizing Committee reviews and approves commodity transaction limits on an individual basis.
- The limits include commodity, physical or financial, tenor (time limit), and dollar amount.
- Only a few individuals are authorized to execute financial hedging transactions.

F. Tampa Electric's Fuels Management Department has updated and formalized its policies and procedures. The key elements of its policies and procedures are:

- Financial hedging of fuel commodities are for mitigation of risk to fuel price uncertainty and volatility.
- Hedging will be conducted in a manner consistent with the Risk Management Plan approved by the RAC.
- Execution of hedges under the Risk Management Plan will be consistent with approved transaction limits for authorized transactors.
- Duties will be separated to assure sufficient control over hedging transactions.
- Hedging activity will be monitored regularly and reported at least once a month to ensure consistency with the Risk Management Plan.

G. Reports are generated that summarize the fuel procurement activities of the company. These include monthly financial reports produced by Regulatory Accounting, FERC Electric Quarterly Reports, FERC Form 1, FERC Form 580, FERC Form 923, FERC Form 552, FPSC Form 423, FPSC A schedules and FPSC E schedules. In addition, position and mark-to-market

reports are produced and reviewed by the Director of Independent Risk Oversight. The appropriate entries and related disclosures are made in the company's books and records as required by accounting standards.

III. Risk Assessment

In its Risk Policy, TECO Energy has identified the following types of risks for its commodity portfolio.

A. Market Risk

Market risk is the potential change in value of a commodity contract caused by adverse changes in market factors (price and volatility). The following are types of market risk.

1. **Price Risk:** Price risk refers to the uncertainty associated with changes in the price of an underlying asset. For instance, if a company has a short position in the market (*e.g*., needs to meet load requirements by purchasing electricity or natural gas), it will be susceptible to price increases. Conversely, if a company is in a long position (*e.g.,* excess generation or natural gas supply), it is exposed to decreases in market prices. Tampa Electric manages its price risk using physical and financial hedges.

   In 2017, Tampa Electric is subject to limited price risk related to variation in coal prices. That price risk is mitigated in part because the company has already contracted for much of its expected coal needs at known prices. Expected market conditions do not currently require further price risk mitigation, for the reasons described in Section IV of this plan.

   Tampa Electric evaluated its exposure to changes in the price for natural gas during 2017 based on the forward price and estimated uncertainty in the price of natural gas and the company's expected usage under both low and high price natural gas cases. Natural gas expenditures decrease in the low case by an estimated $8.2 million and total fuel and purchased power costs decrease by $4.8 million due to lower prices. In the high case, natural gas expenditures increase by an estimated $64.8 million, and the total fuel and purchased power costs increase by $67.8 million. This exposure estimate does not take into account any additional hedges the company may implement to limit its exposure. Tampa Electric's hedging strategy with respect to natural gas and purchased power is outlined in Section IV of this plan.

Tampa Electric requires small quantities of fuel oil and maintains a contract that eliminates its supply risk. Due to the small quantities of fuel oil needed for generation, the cost impact caused by price risk is minimal and is therefore not quantified.

2. **Time Spread Risk:** This is the risk that the relationship between two points (*i.e.,* one month versus six months) on the forward curve changes. Because the shape of the fuel or electricity forward curve changes to reflect the market's expectations of spot and future fuel or electricity prices, the relationship between any two points on the curve is not always constant. Because of the nature of its business Tampa Electric has little reason or opportunity to offset energy commodity requirements in one month with resources delivered in another month. Therefore, time spread risk is not a significant issue for Tampa Electric.

3. **Liquidity Risk:** Liquidity risk is associated with the lack of marketability of a commodity. It includes the risk of an adverse cost or return variation stemming from the lack of marketability of a financial instrument. Liquidity risk may arise because a given position is very large relative to typical trading volumes of like commodity and contract tenor, or because market conditions are unsettled. Liquidity risk is usually reflected in a wide bid-ask spread and large price movements in response to any attempt to buy or sell. A firm facing the need to quickly unwind a portfolio of illiquid instruments may find it necessary to sell at prices far below fair value. Tampa Electric is not exposed to liquidity risk for natural gas financial instruments since the company does not purchase instruments for resale. Tampa Electric does have some liquidity risk for wholesale power transactions since the Florida market has a limited number of participants.

4. **Basis Risk:** Basis risk is the risk exposure due to a difference in commodity value between different delivery points. Electricity markets are regional. Prices can be different at different locations because of differences in both supply costs and the cost of transmission between the two locations. These price differences are dynamic, primarily due to changes in transmission availability between the two locations. Due to the stability of the coal market, Tampa Electric's negligible use of oil, and the indexing of its natural gas contract pricing, basis risk is not a significant issue for the company.

Fundamentally, market risk is created by the existence of "open" positions. An open position is the difference between an existing requirement and the ability to meet that requirement with existing resources.

B. Volume Risk

Volume risk is the potential adverse economic impact of unanticipated changes in supply or demand. Tampa Electric faces supply risk, because there is uncertainty associated with the availability of generating units or fuel availability for those units. If a generating unit fails, Tampa Electric must replace the power with another unit's generation or with purchased power at market prices. Tampa Electric also faces demand risk since there is uncertainty associated with customer demand, and thus uncertainty in the determination of the fuel or energy purchase volumes necessary to supply such demand. Tampa Electric's volume risk for fuel and purchased power in 2017 will be managed operationally and through contract terms enforcement, including appropriate legal remedies, should a party default.

C. Credit Risk

Credit risk is the risk of financial loss due to a counterparty's failure to fulfill the terms of a contract on a timely basis. It includes both settlement risk associated with payment for fuel or energy received, as well as the potential risk that the counterparty defaults on an obligation to provide or receive fuel or energy. Credit risk depends on the probability of counterparty default, the concentration of credit exposure with a small number of counterparties, the total amount of exposure, and the volatility of markets. Tampa Electric's credit risk will vary based on the number of its trading counterparties and the mark-to-market value of its hedge transactions. Tampa Electric's existing credit risk is minimal since it uses a wide variety of counterparties, and has systems and processes in place to monitor and control credit risk.

D. Administrative Risk

Administrative risk is risk of loss associated with deficiencies in a company's internal control structure and management reporting due to human error, fraud or a system's inability to adequately capture, store and report transactions. The company has consistently maintained appropriate administrative controls for entering and administration of commodity transactions.

IV. Risk Management Strategy and Current Hedging Activity

Tampa Electric's risk management strategy is designed to limit exposure to different types of risk that are applicable to the company's operation.

A. Market Risk

Tampa Electric's potential market risk is the result of open positions in four commodities:

- Coal
- Natural Gas
- Fuel Oil
- Purchased Power

System energy requirements during 2017 are projected to be served in the proportions shown in the following table.

Commodity	Percent of System Energy
Coal	46
Natural Gas	52
Purchased Power	2

Based on Tampa Electric's assessment of market risk factors, the company has implemented the market risk management strategies described below.

1. **Coal:** Tampa Electric has contracted for much of its expected coal needs for 2017 through bilateral agreements with coal producers. The company will provide the projected amounts in both tons and dollars in its 2017 projection filing to be submitted September 1, 2016. Coal market pricing has retreated from record high levels in 2008. In 2016, coal prices trended downward due to retiring coal units and pressure from low natural gas prices, and prices are expected to remain stable or may increase slightly in 2017. Tampa Electric has secured a majority of its coal needs for 2017, reducing exposure to price volatility and mitigating coal volume risk. Tampa Electric's contracts with suppliers also incorporate legal remedies in the event of default, which address volume risk.

2. **Fuel Oil:** In 2017, Tampa Electric will continue to purchase its fuel oil needs at indexed market prices. Oil represents less than one percent of the company's needs on a GWH basis, and therefore, associated cost impacts from price risk are minimal. Tampa Electric maintains a contract with a local supplier to deliver all of its needs, which mitigates supply risk.

3. **Natural Gas:** Tampa Electric continues to implement prudent financial hedging strategies for natural gas requirements. In 2016, the company used swap agreements—the exchange of a payment tied to the value of a natural gas index for a fixed payment—to hedge natural gas. In keeping with the company's approved risk management plan, Tampa Electric plans to hedge a percentage of its projected natural gas usage in 2017.

Tampa Electric uses the forward pricing information of the New York Mercantile Exchange ("NYMEX") natural gas forward price curve in developing natural gas price hedging strategy. Tampa Electric also subscribes to industry publications that provide information about underlying issues affecting the availability and price of natural gas and other commodities. The purpose of Tampa Electric's natural gas hedge plan is to reduce natural gas price volatility by utilizing financial instruments relying on three key variables: price, volume and time.

Tampa Electric projects prices during the company's annual fuel budgeting process. The volume of natural gas that the company will hedge falls between a minimum and a maximum percentage of the expected natural gas burn. The percentages vary according to the time remaining until the contract month.

Tampa Electric's approved Risk Management Plan describes the following key elements of the company's natural gas hedging strategy: (1) natural gas prices can be hedged up to 24 months into the future; (2) nearer months can be hedged for a greater percentage of the expected volume than outer months; and (3) natural gas options can be used for financial hedging.

Currently, Tampa Electric estimates about [redacted] percent of its total 2016 natural gas purchases will be covered by financial hedges. The net effect of these hedges is estimated to be a [redacted] of approximately $[redacted]. For 2017, Tampa Electric has approximately [redacted] percent hedged with a currently estimated [redacted] of $[redacted].

4. **Purchased Power:** Total forecasted purchased power for 2017 is 422 GWH. As of July 2016, Tampa Electric has physically hedged 25 GWH's of its 2017 expected purchased power needs through pre-scheduled purchased power agreements. The remaining GWH's of 2017 forecasted wholesale energy purchases will be purchased from as-available cogenerators or on the short-term, non-firm market for economy purposes, which are not hedged.

The company's purchased power contracts include a fuel component; therefore, Tampa Electric has exposure to fuel price risk for its wholesale energy purchases, particularly for purchased power supplied from natural gas-fired generation. Tampa Electric does not currently hedge wholesale energy transactions with financial instruments due to the lack of a liquid, published wholesale energy market and appropriate available instruments.

In summary, Tampa Electric's planned operations in 2017 result in nominal market risk associated with coal and fuel oil. Non-price risks associated with natural gas and purchased power are also minimal. Therefore, while the company continues to evaluate risk for all fuel and energy commodity transactions, it is currently focused on mitigating the price risk associated with natural gas and purchased power.

5. **Volume Risk:** Hedging of volumetric risk is problematic due to a limited number of viable financial hedging instruments. Tampa Electric has identified the following hedges.
   - Maintaining appropriate inventory stockpiles provides a physical hedge against volume risk.
   - "Swing" contracts enable the buyer to take variable volumes up to a predefined limit.
   - Full requirement contracts enable the buyer to take any volume up to total usage.

   Tampa Electric uses inventory swing contracts and full requirements contracts where needed commodity volumes are small and in situations where commodity volumes are unpredictable in volume and/or timing. Other alternatives will continue to be identified, assessed and implemented as necessary.

6. **Credit Risk:** TECO Energy's credit risk management process is composed of the following primary steps.
   - Gather counterparty information for initial evaluation.
   - Assess counterparty creditworthiness and assign credit limit.
   - Determine credit collateral requirements, as needed.
   - Request, review and monitor contractual requirements, legal covenants, collateral documents and credit provisions.
   - Quantify counterparty exposure and measure against approved limits.
   - Monitor counterparty and credit support provider qualities.
   - Prepare credit exposure reports on a daily basis that are reviewed prior to entering into transactions.

7. **Administrative Risk:** Tampa Electric maintains energy trading risk management systems and processes to efficiently track, monitor and evaluate hedging activities. Tampa Electric's administrative processes and system controls have passed repeated internal and external (Sarbanes-Oxley) audits.

REDACTED

Tampa Electric
Natural Gas Hedging Activities
January 1, 2016 through July 31, 2016

	Type of Hedge	Mark-to-Market Saving/(Loss)	Hedged Volume (MMBTU)	Consumption (MMBTU)	Percent Hedged	Budget Price	Hedge Price	Settle Price
Jan-16	Swaps	($2,074,970)	[redacted]	7,131,969	[redacted]	[redacted]	[redacted]	$2.372
Feb-16	Swaps	($2,772,810)	[redacted]	6,630,822	[redacted]	[redacted]	[redacted]	$2.189
Mar-16	Swaps	($3,492,690)	[redacted]	7,902,554	[redacted]	[redacted]	[redacted]	$1.711
Apr-16	Swaps	($3,262,410)	[redacted]	8,891,882	[redacted]	[redacted]	[redacted]	$1.903
May-16	Swaps	($3,127,515)	[redacted]	6,117,238	[redacted]	[redacted]	[redacted]	$1.995
Jun-16	Swaps	($3,403,620)	[redacted]	7,126,182	[redacted]	[redacted]	[redacted]	$1.963
Jul-16	Swaps	$256,280	[redacted]	6,601,646	[redacted]	[redacted]	[redacted]	$2.917
Total		($17,877,735)	[redacted]	50,402,293	[redacted]			

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 56
PARTY: TAMPA ELECTRIC COMPANY – (DIRECT)
DESCRIPTION: J. Brent Caldwell JBC-3

TARIK NORIEGA

111 W. Madison St., Suite 812
Tallahassee, Florida 32399-1300
Office: (850) 488-9330

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 57
PARTY: OFFICE OF PUBLIC COUNSEL – (DIRECT)
DESCRIPTION: Tarik Noriega TN-1

EXPERIENCE

The Florida Legislature – Office of Public Counsel **Tallahassee, Florida**

Economist 2012 – Present

- Serve as an Economist for the Office of Public Counsel (OPC), where I provide analysis and technical support in rate cases and other docketed and undocketed matters on behalf of Florida's utility customers.

State of Florida – Department of Revenue **Tallahassee, Florida**

Research Economist 2011 – 2012

- Served as an Economist in the Office of Tax Research, primarily as the lead analyst in developing the documentary stamp tax and intangibles tax forecasts for the Revenue Estimating Conference (REC). Assisted in developing the ad valorem tax forecast and prepared fiscal impacts for the REC.

The Florida Legislature – House of Representatives **Tallahassee, Florida**

Economist 2008 – 2010

- Served as the Economist for the Military & Local Affairs Policy Committee and the Economic Development & Community Affairs Policy Council, primarily as the lead analyst in reviewing emergency management issues, property tax and local tax issues, libraries and historical/cultural matters, and the sunset reviews for two state agencies. Prepared bill analyses and other documents.

Economist/Budget Analyst 2006 – 2008

- Served as the Economist for the Jobs & Entrepreneurship Council and as the Budget Analyst for the Committee on Utilities & Telecommunications, primarily as the lead analyst in reviewing the budget of the Florida Public Service Commission (PSC). Provided the fiscal analysis for relevant Council and Committee legislation. Tracked REC data, analyzed economic trends, and prepared other Council and Committee documents requested by the members.

Economist 2005 – 2006

- Served as the Economist for the Finance & Tax Committee and the Fiscal Council. Prepared bill analyses and other relevant Committee and Council documents. Tracked revenues and the fiscal impacts for all legislation referred to the Council. Participated in Revenue, Economic, and Demographic Estimating Conferences, analyzed economic trends, and reviewed all relevant economic forecasts.

State Of Florida – Public Service Commission **Tallahassee, Florida**

Regulatory Supervisor/Consultant 2003 – 2005

- Served as the only agency spokesperson handling both English and Spanish media requests. Reviewed PSC staff recommendations to the Commissioners and prepared the agency's response to critical issues attracting media interest. Prepared bilingual press releases and consumer bulletins. Taped bilingual radio and television interviews.

Regulatory Analyst 1996 – 2003

- Evaluated electric utility load forecasts and reported findings and conclusions to the Commission during electric utility ten-year site plan reviews and power plant need determination proceedings. Participated in several telecommunications audits and submitted findings and conclusions to lead auditors. Responsible for the development of several energy and telecommunications policy analysis projects. Designed telephone surveys about the electric, telecommunications, natural gas, water, and wastewater industries. Evaluated all survey data and reported the findings to the Commission and to the Florida Legislature. Monitored federal issues and represented the PSC in various proceedings.

EDUCATION

University Of Central Florida (U.C.F.) – Orlando, Florida 1988 – 1994

- 1994: Master of Arts in Applied Economics (M.A.A.E.)
- 1992: Bachelor of Arts (B.A.) in Economics; Minored in Psychology and English
- Coursework focused on quantitative methods, managerial economics, and money & banking

ACTIVITIES AND HONORS

- Member of Omicron Delta Epsilon, the International Honor Society in Economics (1993-present)
- Secretary of the Provost Advisory Committee – U.C.F. (1994)
- Member of the Dean's Leadership Council – College of Business Administration – U.C.F. (1993-1994)
- President of the U.C.F. Economics Club and the U.C.F. Chapter of Omicron Delta Epsilon (1993-1994)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 58
PARTY: OFFICE OF PUBLIC COUNSEL – (DIRECT)
DESCRIPTION: Tarik Noriega TN-2

Docket No. 160001-EI
IOU Natural Gas Hedging
Gaines/(Losses) From 2002-2015
Exhibit No.__TN-2

IOU NATURAL GAS HEDGING GAINS/(LOSSES) FROM 2002-2015

YEAR	DUKE	FPL	GULF	TECO	TOTAL ANNUAL GAINS/(LOSSES) FOR ALL 4 IOUs
2002	$ (2,098,791)	$ 14,520,306	$ 238,750	$ (203,500)	$ 12,456,765
2003	$ 19,772,126	$ (15,939,810)	$ 4,862,077	$ (2,758,028)	$ 5,936,365
2004	$ 51,068,145	$ 191,564,536	$ 6,652,157	$ 8,413,170	$ 257,698,008
2005	$ 121,672,401	$ 519,388,788	$ 22,571,976	$ 53,231,770	$ 716,864,935
2006	$ 62,066,818	$ (416,637,197)	$ (18,714,562)	$ (54,482,120)	$ (427,767,061)
2007	$ (34,399,955)	$ (799,268,428)	$ (9,197,433)	$ (59,691,520)	$ (902,557,336)
2008	$ 116,935,706	$ 100,709,736	$ (1,737,726)	$ 18,147,375	$ 234,055,091
2009	$ (556,149,474)	$ (1,660,695,829)	$ (51,232,251)	$ (193,185,985)	$ (2,461,263,539)
2010	$ (285,863,553)	$ (509,147,046)	$ (19,667,161)	$ (67,840,710)	$ (882,518,470)
2011	$ (240,882,264)	$ (404,239,340)	$ (15,444,523)	$ (33,889,480)	$ (694,455,607)
2012	$ (351,321,610)	$ (671,819,795)	$ (32,865,554)	$ (61,518,120)	$ (1,117,525,079)
2013	$ (140,907,108)	$ 18,253,045	$ (14,654,866)	$ (3,256,370)	$ (140,565,299)
2014	$ (27,741,075)	$ 116,639,265	$ 1,910,889	$ 15,615,785	$ 106,424,864
2015	$ (225,543,645)	$ (504,393,229)	$ (50,572,362)	$ (39,842,325)	$ (820,351,561)
TOTAL GAINS/(LOSSES) BY IOU FROM 2002-2015	**$ (1,493,392,279)**	**$ (4,021,064,998)**	**$ (177,850,589)**	**$ (421,260,058)**	**$ (6,113,567,924)**

Responses To Mid-course Correction Discovery

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 59
PARTY: OFFICE OF PUBLIC COUNSEL – (DIRECT)
DESCRIPTION: Tarik Noriega TN-3

Florida Power & Light Company
Docket No. 150001-EI
OPC's 4th Set of Interrogatories
Interrogatory No. 30
Page 1 of 1

Q.

During the period 1999 through 2014:

a. In what years did the Company petition for a mid-course correction to its fuel cost recovery or capacity cost recovery factors for an over-recovery?

b. In what years did the Company petition for a mid-course correction for an underrecovery?

c. What was the percentage change to the fuel cost recovery or capacity cost recovery factor for each mid-course correction?

d. What was the root cause(s) of the request for the mid-course correction?

A.

Please see chart below for response.

(a)/(b)	(a)/(b)	(a)/(b)	(c)	(d)
YEAR	CLAUSE	MIDCOURSE TYPE	% CHANGE IN FUEL FACTOR	ROOT CAUSE
2000	Fuel	Under-recovery	23%	Increase in fuel charge due to higher than projected heavy oil price reflecting OPEC's adherence to their supply agreement
2001	Fuel	Under-recovery	25%	Increase in fuel charge due to unprecedented increase in oil and natural gas prices
2002	Fuel	Over-recovery	-8%	Decrease in fuel charge due to refund of projected over-recovery as part of settlement agreement
2003	Fuel	Under-recovery	17%	Increase in fuel charge due to higher than projected oil and natural gas prices as a result of colder than normal weather in gas burning regions of North America, lower imports of natural gas, low oil inventory in the U.S., increasing tensions in the Middle East in anticipation of a war, and unanticipated and continued oil worker's strike in Venezuela
2003	Fuel	Under-recovery	16%	Increase in fuel charge due to higher than projected natural gas and oil prices and higher than projected load
2008	Fuel	Under-recovery	29%	Increase in fuel charge due to dramatic increases in worldwide fuel oil prices
2008	Fuel	Over-recovery	-18%	Decrease in fuel charge due to downward trend in natural gas and fuel oil prices
2011	Fuel	Over-recovery	-11%	Decrease in fuel charge due to a decrease in projected 2012 natural gas prices

Citizens' First Set of Interrogatories
GULF POWER COMPANY
Docket No. 150001-EI
May 22, 2015
Item No. 6
Page 1 of 1

6. During the period 1999 through 2014:
   a. In what years did the Company petition for a mid-course correction to its fuel cost recovery or capacity cost recovery factors for an over-recovery?
   b. In what years did the Company petition for a mid-course correction for an under-recovery?
   c. What was the percentage change to the fuel cost recovery or capacity cost recovery factor for each mid-course correction?
   d. What was the root cause(s) of the request for the mid-course correction?

ANSWER:

(a-b) Year	(a-b) Clause	(a-b) Recovery Position	(c) % Change	(d) Root Cause
2008	Fuel	Under Recovery	28%	Higher than estimated fuel prices.
2012	Fuel	Over Recovery	(7%)	Unexpected falling natural gas prices and unexpected 2011 over recovery for 2011 final true-up amount
2012	Fuel	Over Recovery	(21%)	Lower than expected natural gas prices and availability of firm transmission for Shell Energy PPA

TAMPA ELECTRIC COMPANY
DOCKET NO. 150001-EI
OPC'S FIRST SET OF
INTERROGATORIES
INTERROGATORY NO. 6
PAGE 1 OF 2
FILED: MAY 26, 2015

6. During the period 1999 through 2014:

   a. In what years did the Company petition for a mid-course correction to its fuel cost recovery or capacity cost recovery factors for an over-recovery?

   b. In what years did the Company petition for a mid-course correction for an under-recovery?

   c. What was the percentage change to the fuel cost recovery or capacity cost recovery factor for each mid-course correction?

   d. What was the root cause(s) of the request for the mid-course correction?

A. a. During the period 1999 through 2014, Tampa Electric petitioned for a mid-course correction in the fuel and capacity cost recovery clauses in 2000, and the fuel clause in 2001, 2003 and 2009.

   b. Tampa Electric petitioned for a mid-course correction due to an under-recovery in the fuel clause in 2000, 2001, and 2003.

   c. Please see the table below for the percentage change to the fuel or capacity cost recovery factor.

Mid-Course Correction Year	Percentage Change	
	Fuel	Capacity
2000	8%	39%
2001	13%	0
2003	14%	0
2009	(21%)	0

   d. The root causes of Tampa Electric's requests for mid-course correction are described in the company's petitions for mid-course correction, which documents can be found at the following locations:

TAMPA ELECTRIC COMPANY
DOCKET NO. 150001-EI
OPC'S FIRST SET OF
INTERROGATORIES
INTERROGATORY NO. 6
PAGE 2 OF 2
FILED: MAY 26, 2015

2000
http://www.floridapsc.com/library/FILINGS/00/05474-00/05474-00.pdf

2001
http://www.floridapsc.com/library/FILINGS/01/01930-01/01930-01.PDF

2003
http://www.floridapsc.com/library/FILINGS/03/01866-03/01866-03.PDF

2009
http://www.floridapsc.com/library/FILINGS/09/01805-09/01805-09.pdf

Responses To Hedging Gains/(Losses) Discovery

Docket No. 150001
DEF's Amended Response to OPC's 1st Rogs (1-13)
Q2
DEF-15FL-FUEL-00267

	Natural Gas Savings (Cost)	#6 Oil Savings (Cost)	#2 Oil Savings (Cost)	River Barge/Rail Fuel Surcharge Savings (Cost)	Natural Gas Storage Savings (Cost)	Total Net Hedging Savings (Cost)
	See Note 1				See Note 1	
2002	($2,098,791)	($1,533,222)	$0	$0	$0	($3,632,013)
2003	$19,772,126	($1,229,174)	$0	$0	$0	$18,542,952
2004	$51,068,145	($758,433)	$0	$0	$0	$50,309,712
2005	$121,672,401	$70,386,665	$0	$0	$0	$192,059,066
2006	$62,066,818	$58,539,042	($1,606,710)	$0	$0	$118,999,150
2007	($34,399,955)	$18,382,023	$943,446	$0	$0	($15,074,486)
2008	$116,935,706	$106,527,933	$13,035,568	$0	$3,268,288	$239,767,495
2009	($556,149,474)	($17,029,960)	($9,937,473)	$0	($478,125)	($583,595,032)
2010	($285,863,553)	$3,400,207	$789,615	($237,316)	($13,125)	($281,930,172)
2011	($240,882,264)	$4,356,425	$3,044,674	$2,240,474	$6,750	($231,233,941)
2012	($351,321,610)	$4,456,315	$382,080	$908,953	($205,913)	($345,780,175)
2013	($140,907,108)	$0	($213,675)	($219,072)	$25,575	($141,314,280)
2014	($27,741,075)	$0	($133,341)	($594,097)	$3,225	($28,465,288)

Note 1:

DEF is revising its response to OPC's First Set of Interrogatories question 2. The Natural Gas Storage amounts have been removed from the Natural Gas Savings (Cost) totals for the years 2008 through 2014 and placed in a column called Natural Gas Storage Savings (Cost). The Total Net Hedging Savings (Cost) totals for this table have not changed. The Natural Gas Storage amounts were moved to the Natural Gas Storage Savings Cost Column and were included in DEF's original response submitted on May 26, 2015.

DUKE ENERGY FLORIDA

DOCKET NO. 160001-EI

Fuel and Capacity Cost Recovery
Final True-Up for the Period
January through December 2015

DIRECT TESTIMONY OF JOSEPH MCCALLISTER

April 6, 2016

Q. Please state your name and business address.

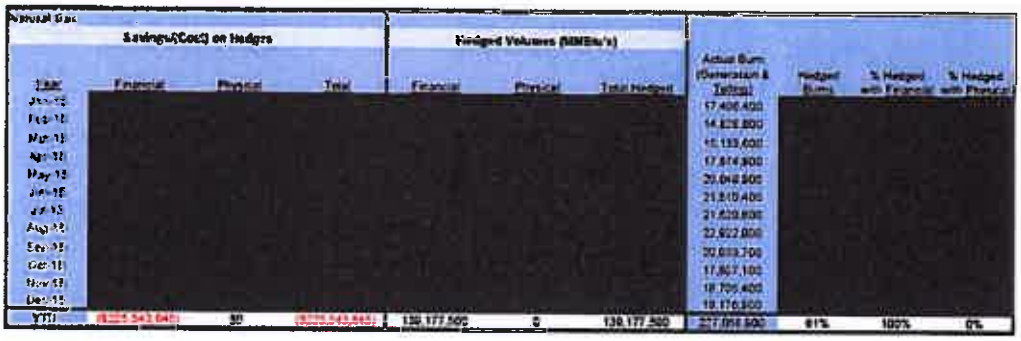
A. My name is Joseph McCallister. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

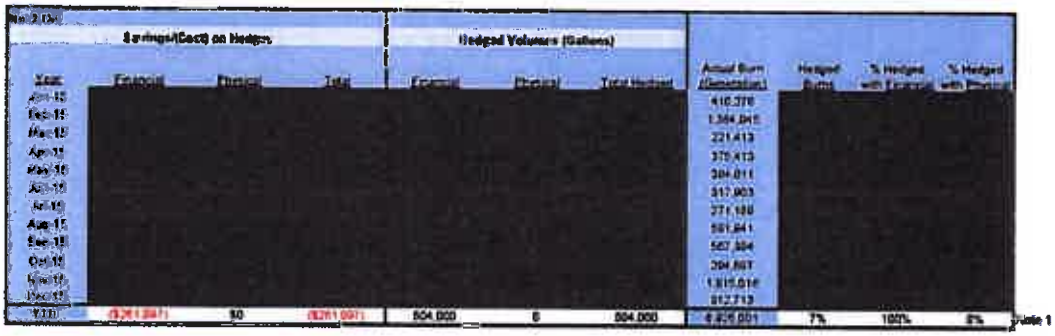
Q. By whom are you employed and in what capacity?

A. I work for Duke Energy Progress, an affiliate company of Duke Energy Florida, LLC ("DEF" or "Company") as the Director, Natural Gas Oil and Emissions. I am responsible for the natural gas, fuel oil and emission group activities in the Fuel Procurement Section of the Systems Optimization Department for the Duke Energy regulated generation fleet. This group is responsible for the natural gas and fuel oil acquisition and transportation needed to support the generation needs for Duke Energy Indiana ("DEI"), Duke Energy Kentucky ("DEK"), Duke Energy Carolinas ("DEC"), Duke Energy Progress ("DEP"), and DEF. In addition, this group is responsible

REDACTED

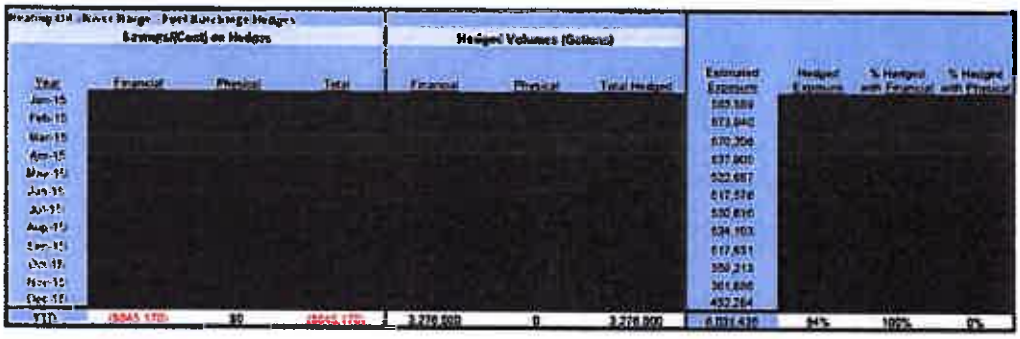
Duke Energy Florida
Natural Gas and Oil Hedging Detail

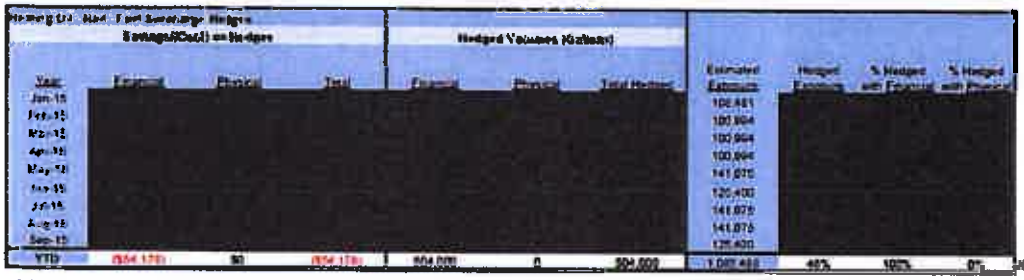




Note 1







Note 2

Note 1: For the period of January 2015 through December 2015, based on forecasted burns for 2015, DEF fuel oil hedge percentage was approximately [redacted]. This was above the minimum hedge target of [redacted]. During 2015, actual fuel oil usage was higher than forecasts which resulted in the overall lower actual hedge percentage.

Note 2: As outlined in DEF's 2015 Risk Management Plan, with respect to estimated fuel surcharge exposures in its coal rail transportation agreement, given the reduction in rail shipments during the latter part of 2015, and the expiration of the rail agreement at the end of December 2015, DEF did not estimate or hedge rail exposures for periods beyond September 2015. For the twelve-month period of August 2014 through July 2015, DEF's estimated rail surcharge hedge percentage was approximately [redacted]. Also, for the period of January 2015 through September 2015, DEF's overall rail surcharge hedge percentage was approximately [redacted] which was within the target range of [redacted].

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor	Docket No. 160001-EI Dated: May 23, 2016

DUKE ENERGY FLORIDA, LLC'S RESPONSES TO CITIZENS' FIRST SET OF INTERROGATORIES (NOS. 1-10)

Duke Energy Florida, LLC ("DEF"), responds to the Citizens of the State of Florida, through the Office of the Public Counsel's ("Citizens" or "OPC") First Set of Interrogatories to DEF (Nos. 1-10), as follows:

INTERROGATORIES

1. What are the Company's cumulative natural gas hedging gains or losses from 2002 through 2015?

Answer:

DEF's cumulative natural gas hedging cost is approximately $1.493 billion from 2002 through 2015, and approximately $1.491 billion including hedging transactions for natural gas storage purchases.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor	Docket No. 160001-EI Dated: August 22, 2016

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO CITIZENS' SECOND SET OF INTERROGATORIES (NOS. 11-18)

Duke Energy Florida, LLC ("DEF"), responds to the Citizens of the State of Florida, through the Office of the Public Counsel's ("Citizens" or "OPC") Second Set of Interrogatories to DEF (Nos. 11-18) as follows:

INTERROGATORIES

11. Natural gas financial hedging gain or loss for 2016 as of July 31, 2016:

a. Please update the projected amount of the anticipated natural gas financial hedging loss that was provided in the Company's May 2016 response to OPC Interrogatory No. 2.

Answer:

For natural gas, DEF is currently estimating a net hedge cost for calendar year 2016 of approximately $145.5 million based on July 29, 2016 closing market prices. The date of July 29, 2016 is being used to estimate as it is the last business day of the month that prices were published and July 31, 2016 is a Sunday.

b. What was the actual natural gas financial hedging loss from January 1 through July 31, 2016?

Answer:

For natural gas, DEF net hedge cost from January 1 through July 31, 2016 was approximately $114.9 million.

c. What is the estimated amount of natural gas financial hedging gain or loss from August 1 through December 31, 2016?

Answer:

For natural gas, DEF is currently estimating a net hedge cost for August 1 through December 31, 2016 of approximately $30.6 million based on July 29, 2016 closing market prices. The date of July 29, 2016 is being used to estimate as it is the last business day of the month that prices were published as July 31, 2016 is a Sunday.

d. Since the Company's May 2016 response to OPC on the projected 2016 natural gas financial hedging loss, please explain whether the 2016 projected loss has increased or decreased and by how much in terms of dollars and percentages.

Answer:

The projected 2016 natural gas financial hedge cost has decreased from the May 2016 response to OPC. DEF is currently estimating the projected 2016 natural gas financial hedging cost to decrease by approximately $29.2 million or approximately 17% from the May 2016 projection based on actual hedge cost for January 2016 through July 2016, and estimated net hedge costs for the months of August 2016 through December 2016 based on July 29, 2016 closing market price. The date of July 29, 2016 is being used to estimate as it is the last business day of the month that prices were published and July 31, 2016 is a Sunday.

12. **Projected natural gas financial hedging gains or losses for 2017 as of July 31, 2016:**

a. **Please provide the projected natural gas hedging gain or loss for calendar year 2017 based on the hedging positions the Company has already executed.**

Answer:

The estimated natural gas hedge cost for calendar year 2017 based on market prices as of July 29, 2016 is approximately $25.8 million. The date of July 29, 2016 is being used to estimate as it is the last business day of the month that prices were published and July 31, 2016 is a Sunday.

REDACTED

b. **As part of this response, what percentage of the total anticipated natural gas burn for 2017 has already been hedged?**

Answer:

As of July 29, 2016, DEF has hedged approximately [redacted] percent of its forecasted natural gas burns for calendar year 2017. The date of July 29, 2016 is being used to estimate as it is the last business day of the month that prices were published versus July 31, 2016 which is a Sunday.

Florida Power & Light Company
Docket No. 160001-EI
OPC's 1st Set of Interrogatories
Interrogatory No. 1
Page 1 of 1

Q.

What are the Company's cumulative natural gas hedging gains or losses from 2002 through 2015?

A.

The data in this answer includes both financial and physical hedges. The answer may need to be modified when the Florida Supreme Court's order in Docket SC15-95 becomes final.

FPL's natural gas hedging gains and losses from 2002 through 2015 are summarized in the attached table.

FPL HEDGING RESULTS	
	Natural Gas Gain(Loss)
2002	14,520,306
2003	(15,939,810)
2004	191,564,536
2005	519,388,788
2006	(416,637,197)
2007	(799,268,428)
2008	100,709,736
2009	(1,660,695,829)
2010	(509,147,046)
2011	(404,239,340)
2012	(671,819,795)
2013	18,253,045
2014	116,639,265
2015	(504,393,229)
TOTAL	(4,021,064,999)

Florida Power & Light Company
Docket No. 160001-EI
OPC's 3rd Set of Interrogatories
Interrogatory No. 66
Page 1 of 1

Q.

Natural gas financial hedging gain or loss for 2016 as of July 31, 2016:

a. **Please update the projected amount of the anticipated natural gas financial hedging loss that was provided in the Company's May 2016 response to OPC Interrogatory No.2.**

b. **What was the actual natural gas financial hedging loss from January 1 through July 31, 2016?**

c. **What is the estimated amount of natural gas financial hedging gain or loss from August 1 through December 31, 2016?**

d. **Since the Company's May 2016 response to OPC on the projected 2016 natural gas financial hedging loss, please explain whether the 2016 projected loss has increased or decreased and by how much in terms of dollars and percentages?**

A.

a. Based on the August 1, 2016 forward curve, FPL currently estimates hedging costs of ($225,389,374) for calendar year 2016.

b. The natural gas financial hedging results from January 1, 2016 to July 31, 2016 were a net cost of ($190,763,980).

c. Based on the August 1, 2016 forward curve, FPL currently estimates hedging costs of approximately ($34,625,394) from August 1, 2016 through December 31, 2016.

d. The Company's projected 2016 hedging cost has decreased by $83,670,156, or approximately 27% since May 2016.

Florida Power & Light Company
Docket No. 160001-EI
OPC's 3rd Set of Interrogatories
Interrogatory No. 67
Page 1 of 1

Q.

Projected natural gas financial hedging gains or losses for 2017 as of July 31, 2016:

a. **Please provide the projected natural gas hedging gain or loss for calendar year 2017 based on the hedging positions the Company has already executed.**

b. **As part of this response, what percentage of the total anticipated natural gas burn for 2017 has already been hedged?**

A.

a) Based on the August 1, 2016 forward curve, FPL currently estimates a natural gas financial hedging benefit of $51,032,744 for calendar year 2017, from transactions in place at the end of July 2016.

b) At the end of July 2016, FPL had financially hedged approximately [redacted] of the total projected natural gas burn for 2017.

Citizens' First Set of Interrogatories
GULF POWER COMPANY
Docket No. 160001-EI
Revised September 21, 2016
Item No. 1
Page 1 of 1

1. **What are the Company's cumulative natural gas hedging gains or losses from 2002 through 2015?**

ANSWER:

	Natural Gas Gain (loss) $
2002	238,750
2003	4,862,077
2004	6,652,157
2005	22,571,976
2006	(18,714,562)
2007	(9,197,433)
2008	(1,737,726)
2009	(51,232,251)
2010	(19,667,161)
2011	(15,444,523)
2012	(32,865,554)
2013	(14,654,866)
2014	1,910,889
2015	(50,572,362)
Total	(177,850,589)

Citizens' Second Set of Interrogatories
GULF POWER COMPANY
Docket No. 160001-EI
August 22, 2016
Item No. 11
Page 1 of 1

11. Natural gas financial hedging gain or loss for 2016 as of July 31, 2016:
    a. Please update the projected amount of the anticipated natural gas financial hedging loss that was provided in the Company's May 2016 response to OPC Interrogatory No. 2.
    b. What was the actual natural gas financial hedging loss from January 1 through July 31, 2016?
    c. What is the estimated amount of natural gas financial hedging gain or loss from August 1 through December 31, 2016?
    d. Since the Company's May 2016 response to OPC on the projected 2016 natural gas financial hedging loss, please explain whether the 2016 projected loss has increased or decreased and by how much in terms of dollars and percentages.

ANSWER:

a. Gulf anticipates reporting a net hedging loss for calendar year 2016 of approximately $54,569,118.

b. Gulf's actual natural gas financial hedging loss from January 1 through July 31, 2016 was $37,505,696.

c. As reported in Gulf's Estimated/Actual filed August 4, 2016, Gulf projects a $17,063,422 hedging loss for August 1 through December 31, 2016.

d. Gulf's current estimate of a natural gas hedging loss for calendar year 2016 of approximately $54,569,118 represents a $3,430,882, or 5.9%, decrease from the $58,000,000 estimate provided in Gulf's response to Citizens' first set of interrogatories in the May 2016.

Citizens' Second Set of Interrogatories
GULF POWER COMPANY
Docket No. 160001-EI
August 22, 2016
Item No. 12
Page 1 of 1

12. Projected natural gas financial hedging gains or losses for 2017 as of July 31, 2016:
    a. Please provide the projected natural gas hedging gain or loss for calendar year 2017 based on the hedging positions the Company has already executed.
    b. As part of this response, what percentage of the total anticipated natural gas burn for 2017 has already been hedged?

ANSWER:

a. The current estimate, as of July 31, 2016, of net financial hedging loss for calendar year 2017 is approximately $18,000,000.

b. As of July 31, 2016, Gulf has hedged approximately [redacted] of the 2017 natural gas burn anticipated in its 2016 Energy Budget.

TAMPA ELECTRIC COMPANY
DOCKET NO. 150001-EI
OPC'S FIRST SET OF
INTERROGATORIES
INTERROGATORY NO. 2
PAGE 1 OF 2
FILED: MAY 26, 2015

2. For each of the years from 2002 through 2014, what was the annual gain or loss on each type of commodity hedged by the Company (referenced in the Company's answer to Interrogatory No. 25), as part of this response, what was the total net annual gain or loss for all the commodities hedged during that year? Please respond using a table format similar to the one below and add additional columns for hedged commodities.

	Natural Gas Gain (loss)	Oil Gain (loss)	Other Commodities Gain (loss)	Total Net Hedging Gain (loss)
2002				
2003				
2004				
2005				
2006				
2007				
2008				
2009				
2010				
2011				
2012				
2013				
2014				
Total				

A. The requested information is provided in the table on the following page. Tampa Electric does not use financial hedges for oil or other commodities.

TAMPA ELECTRIC COMPANY
DOCKET NO. 150001-EI
OPC'S FIRST SET OF
INTERROGATORIES
INTERROGATORY NO. 2
PAGE 2 OF 2
FILED: MAY 26, 2015

	Natural Gas Gain (loss)	Oil Gain (loss)	Other Commodities Gain (loss)	Total Net Hedging Gain (loss)
2002	($203,500)	0	0	($203,500)
2003	($2,758,028)	0	0	($2,758,028)
2004	$8,413,170	0	0	$8,413,170
2005	$53,231,770	0	0	$53,231,770
2006	($54,482,120)	0	0	($54,482,120)
2007	($59,691,520)	0	0	($59,691,520)
2008	$18,147,375	0	0	$18,147,375
2009	($193,185,985)	0	0	($193,185,985)
2010	($67,840,710)	0	0	($67,840,710)
2011	($33,889,480)	0	0	($33,889,480)
2012	($61,518,120)	0	0	($61,518,120)
2013	($3,256,370)	0	0	($3,256,370)
2014	$15,615,785	0	0	$15,615,785

TAMPA ELECTRIC

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 160001-EI

IN RE: FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

2015 HEDGING ACTIVITY TRUE-UP

TESTIMONY AND EXHIBIT

J. BRENT CALDWELL

FILED: APRIL 6, 2016

Tampa Electric Company
Natural Gas Hedging Activities
January 1, 2015 through December 31, 2015

	Type of Hedge	Mark-to-Market Saving/(Loss)	Hedged Volume (MMBTU)	Consumption (MMBTU)	Percent Hedged	Budget Price	Hedge Price	Settle Price
Jan-15	Swaps	($2,576,655)		4,459,415				$3.189
Feb-15	Swaps	($3,450,145)		4,073,535				$2.866
Mar-15	Swaps	($3,338,845)		6,272,889				$2.894
Apr-15	Swaps	($3,428,830)		5,842,268				$2.590
May-15	Swaps	($4,357,580)		7,263,430				$2.517
Jun-15	Swaps	($3,356,285)		8,097,636				$2.815
Jul-15	Swaps	($3,627,895)		8,092,380				$2.773
Aug-15	Swaps	($2,610,980)		8,045,798				$2.886
Sep-15	Swaps	($3,571,100)		7,453,216				$2.638
Oct-15	Swaps	($3,488,100)		6,996,753				$2.563
Nov-15	Swaps	($3,288,730)		5,773,557				$2.033
Dec-15	Swaps	($2,747,180)		4,259,752				$2.206
Total		($39,842,325)		76,630,630				

Consistent with Tampa Electric's non-speculative risk management plan objective, Tampa Electric's natural gas hedging plan provided price stability and certainty during 2015. For 2015, the calendar year net position for natural gas hedges was higher than the closing price of natural gas, resulting in a mark-to-market net loss of $39.8 million. Natural gas prices dropped significantly in 2015 due to an abundance of natural gas production and nearly full storage at the end of the summer injection season.

Tampa Electric maintains natural gas storage capacity of 1,500,000 MMBtu in order 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 a net loss of approximately $39.8 million in 2015; more importantly, Tampa Electric was

TAMPA ELECTRIC COMPANY
DOCKET NO. 160001-EI
OPC'S FIRST SET OF
INTERROGATORIES
INTERROGATORY NO. 1
PAGE 1 OF 1
FILED: MAY 23, 2016

1. What are the Company's cumulative natural gas hedging gains or losses from 2002 through 2015?

A. Tampa Electric's cumulative net natural gas hedging results for 2002 through 2015 is a cost of $421,260,058.

TAMPA ELECTRIC COMPANY
DOCKET NO. 160001-EI
OPC'S SECOND SET OF
INTERROGATORIES
INTERROGATORY NO. 11
PAGE 1 OF 1
FILED: AUGUST 22, 2016

11. Natural gas financial hedging gain or loss for 2016 as of July 31, 2016:

a. Please update the projected amount of the anticipated natural gas financial hedging loss that was provided in the Company's May 2016 response to OPC Interrogatory No.2.

b. What was the actual natural gas financial hedging loss from January 1 through July 31, 2016?

c. What is the estimated amount of natural gas financial hedging gain or loss from August 1 through December 31, 2016?

d. Since the Company's May 2016 response to OPC on the projected 2016 natural gas financial hedging loss, please explain whether the 2016 projected loss has increased or decreased and by how much in terms of dollars and percentages.

A. a. Tampa Electric projects it will have a natural gas financial hedging loss of $18,460,765 for 2016.

b. As reported in Tampa Electric's Hedging Activity Report filed on August 18, 2016, the results for January 1, 2016 through July 31, 2016 are a loss of $17,877,735.

c. The projected natural gas financial hedging loss for the period August 1, 2016 through December 31, 2016 is $583,030.

d. Tampa Electric's projected 2016 loss has increased by $309,600, which equates to a 1.7 percent change.

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 160001-EI
OPC'S SECOND SET OF
INTERROGATORIES
INTERROGATORY NO. 12
PAGE 1 OF 1
FILED: AUGUST 22, 2016

12. Projected natural gas financial hedging gains or losses for 2017 as of July 31, 2016:

    a. Please provide the projected natural gas hedging gain or loss for calendar year 2017 based on the hedging positions the Company has already executed.

    b. As part of this response, what percentage of the total anticipated natural gas burn for 2017 has already been hedged?

A. a. Tampa Electric projects a natural gas hedging gain of $3,201,935 for 2017.

    b. Tampa Electric has hedged approximately [redacted] of its expected natural gas usage for 2017.

DANIEL J. LAWTON
B.A. ECONOMICS, MERRIMACK COLLEGE
M.A. ECONOMICS, TUFTS UNIVERSITY

Prior to beginning his own consulting practice Diversified Utility Consultants, Inc., in 1986 where he practiced as a firm principal through December 31, 2005, Mr. Lawton had been in the utility consulting business with a national engineering and consulting firm. In addition, Mr. Lawton has been employed as a senior analyst and statistical analyst with the Department of Public Service in Minnesota. Prior to Mr. Lawton's involvement in utility regulation and consulting he taught economics, econometrics, statistics and computer science at Doane College.

Mr. Lawton has conducted numerous revenue requirements, fuel reconciliation reviews, financial, and cost of capital studies on electric, gas and telephone utilities for various interveners before local, state and federal regulatory bodies. In addition, Mr. Lawton has provided studies, analyses, and expert testimony on statistics, econometrics, accounting, forecasting, and cost of service issues. Other projects in which Mr. Lawton has been involved include rate design and analyses, prudence analyses, fuel cost reviews and regulatory policy issues for electric, gas and telephone utilities. Mr. Lawton has developed software systems, databases and management systems for cost of service analyses.

Mr. Lawton has developed numerous forecasts of energy and demand used for utility generation expansion studies as well as municipal financing. Mr. Lawton has represented numerous municipalities as a negotiator in utility-related matters. Such negotiations range from the settlement of electric rate cases to the negotiation of provisions in purchase power contracts.

In addition to rate consulting work, Mr. Lawton through the Lawton Law Firm represents numerous municipalities in Texas before regulatory authorities in electric and gas proceedings. Mr. Lawton also represents municipalities in various contract and franchise matters involving gas and electric utility matters.

A list of cases in which Mr. Lawton has provided testimony is attached.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 60
PARTY: OFFICE OF PUBLIC COUNSEL – (DIRECT)
DESCRIPTION: Daniel J. Lawton DJL-1

UTILITY RATE PROCEEDINGS IN WHICH TESTIMONY HAS BEEN PRESENTED BY DANIEL J. LAWTON

PUBLIC UTILITIES COMMISSION OF CALIFORNIA		
Southern California Edison	12-0415	Cost of Capital

ALASKA REGULATORY COMMISSION		
Beluga Pipe Line Company Municipal Light & Power Enstar Natural Gas Co.	P-04-81 U-13-184 U-14-111	Cost of Capital Cost of Capital Cost of Capital
San Diego Gas and Electric	12-0416	Cost of Capital
Southern California Gas	12-0417	Cost of Capital
Pacific Gas and Electric	12-0418	Cost of Capital

GEORGIA PUBLIC SERVICE COMMISSION		
Georgia Power Co.	25060-U	Cost of Capital

FEDERAL ENERGY REGULATORY COMMISSION		
Alabama Power Company	ER83-369-000	Cost of Capital
Arizona Public Service Company	ER84-450-000	Cost of Capital
Florida Power & Light	EL83-24-000	Cost Allocation, Rate Design
Florida Power & Light	ER84-379-000	Cost of Capital, Rate Design, Cost of Service
Southern California Edison	ER82-427-000	Forecasting

LOUISIANA PUBLIC SERVICE COMMISSION		
Louisiana Power & Light	U-15684	Cost of Capital, Depreciation

Louisiana Power & Light	U-16518	Interim Rate Relief
Louisiana Power & Light	U-16945	Nuclear Prudence, Cost of Service

MARYLAND PUBLIC SERVICE COMMISSION		
Baltimore Gas and Electric Company	9173	Financial
Baltimore Gas and Electric Company	9326	Financial

MINNESOTA PUBLIC UTILITIES COMMISSION		
Continental Telephone	P407/GR-81-700	Cost of Capital
Interstate Power Co.	E001/GR-81-345	Financial
Montana Dakota Utilities	G009/GR-81-448	Financial, Cost of Capital
New ULM Telephone Company	P419/GR81767	Financial
Norman County Telephone	P420/GR-81-230	Rate Design, Cost of Capital
Northern States Power	G002/GR80556	Statistical Forecasting, Cost of Capital
Northwestern Bell	P421/GR80911	Rate Design, Forecasting

MISSUORI PUBLIC SERVICE COMMISSION		
Missouri Gas Energy	GR-2009-0355	Financial
Ameren UE	ER-2010-0036	Financial

FLORIDA PUBLIC SERVICE COMMISSION		
Progress Energy	070052-EI	Cost Recovery
Florida Power and Light	080677-EI	Financial
Florida Power and Light	090130-EI	Depreciation

Progress Energy	090079-EI	Depreciation
Florida Power and Light	120015-EI	Financial Metrics
Florida Power and Light	140001-EI	Economic and Regulatory Policy Issues
Florida Power and Light	150001-EI	Economic and Regulatory Policy Issues Financial Gas Hedging
Florida Power and Light	160021-EI	Return on Equity Incentives & Financial Integrity

NORTH CAROLINA UTILITIES COMMISSION		
North Carolina Natural Gas	G-21, Sub 235	Forecasting, Cost of Capital, Cost of Service

OKLAHOMA PUBLIC SERVICE COMMISSION		
Arkansas Oklahoma Gas Corporation	200300088	Cost of Capital
Public Service Company of Oklahoma	200600285	Cost of Capital
Public Service Company of Oklahoma	200800144	Cost of Capital
Public Service Company of Oklahoma	201200054	Financial and Earnings Related
Oklahoma Natural Gas	201500213	Return on Equity, Financial, capital Structure

PUBLIC SERVICE COMMISSION OF INDIANA		
Kokomo Gas & Fuel Company	38096	Cost of Capital

PUBLIC UTILITY COMMISSION OF NEVADA		
Nevada Bell	99-9017	Cost of Capital
Nevada Power Company	99-4005	Cost of Capital
Sierra Pacific Power Company	99-4002	Cost of Capital
Nevada Power Company	08-12002	Cost of Capital
Southwest Gas Corporation	09-04003	Cost of Capital
Sierra Pacific Power Company	10-06001 & 10-06002	Cost of Capital & Financial
Nevada Power Co. and Sierra Pacific Power Co.	11-06006 11-06007 11-06008	Cost of Capital
Southwest Gas Corp.	12-04005	Cost of Capital
Sierra Power Company	13-06002 13-06003 13-06003	Cost of Capital
NV Energy & MidAmerican Energy Holdings Co.	13-07021	Merger and Public Interest Financial

Sierra Power Company	16-06006 16-06007	Cost of Capital

PUBLIC SERVICE COMMISSION OF UTAH		
PacifiCorp	04-035-42	Cost of Capital
Rocky Mountain Power	08-035-38	Cost of Capital
Rocky Mountain Power	09-035-23	Cost of Capital
Rocky Mountain Power	10-035-124	Cost of Capital

Rocky Mountain Power	11-035-200	Cost of Capital
Questar Gas Company Rocky Mountain Power	13-057-05 13-035-184	Cost of Capital Cost of Capital

SOUTH CAROLINA PUBLIC SERVICE COMMISSION		
Piedmont Municipal Power	82-352-E	Forecasting

PUBLIC UTILITY COMMISSION OF TEXAS		
Central Power & Light Company	6375	Cost of Capital, Financial Integrity
Central Power & Light Company	9561	Cost of Capital, Revenue Requirements
Central Power & Light Company	7560	Deferred Accounting
Central Power & Light Company	8646	Rate Design, Excess Capacity
Central Power & Light Company	12820	STP Adj. Cost of Capital, Post Test-year adjustments, Rate Case Expenses
Central Power & Light Company	14965	Salary & Wage Exp., Self-Ins. Reserve, Plant Held for Future use, Post Test Year Adjustments, Demand Side Management, Rate Case Exp.
Central Power & Light Company	21528	Securitization of Regulatory Assets
El Paso Electric Company	9945	Cost of Capital, Revenue Requirements, Decommissioning Funding
El Paso Electric Company	12700	Cost of Capital, Rate Moderation Plan, CWIP, Rate Case Expenses
Entergy Gulf States Incorporated	16705	Cost of Service, Rate Base, Revenues, Cost of Capital, Quality of Service
Entergy Gulf States Incorporated	21111	Cost Allocation
Entergy Gulf States Incorporated	21984	Unbundling

Entergy Gulf States Incorporated	22344	Capital Structure
Entergy Gulf States Incorporated	22356	Unbundling
Entergy Gulf States Incorporated	24336	Price to Beat
Gulf States Utilities Company	5560	Cost of Service
Gulf States Utilities Company	6525	Cost of Capital, Financial Integrity
Gulf States Utilities Company	6755/7195	Cost of Service, Cost of Capital, Excess Capacity
Gulf States Utilities Company	8702	Deferred Accounting, Cost of Capital, Cost of Service
Gulf States Utilities Company	10894	Affiliate Transaction
Gulf States Utilities Company	11793	Section 63, Affiliate Transaction
Gulf States Utilities Company	12852	Deferred acctng., self-Ins. reserve, contra AFUDC adj., River Bend Plant specifically assignable to Louisiana, River Bend Decomm., Cost of Capital, Financial Integrity, Cost of Service, Rate Case Expenses
GTE Southwest, Inc.	15332	Rate Case Expenses
Houston Lighting & Power	6765	Forecasting
Houston Lighting & Power	18465	Stranded costs
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Southwestern Electric Power Company	5301	Cost of Service
Southwestern Electric Power Company	4628	Rate Design, Financial Forecasting
Southwestern Electric Power Company	24449	Price to Beat Fuel Factor
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Southwestern Bell Telephone Company	18509	Rate Group Re-Classification
Southwestern Public Service	13456	Interruptible Rates

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Texas Utilities Electric Company	11735	Revenue Requirements
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West Texas Utilities Company	13369	Rate Design

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Energas Company	8205	Cost of Capital
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Lone Star Gas Company-Transmission	8935	Implementation of Billing Cycle Adjustment
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		Costs
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TXU Lone Star Pipeline	8976	Cost of Capital, Capital Structure
TXU-Gas Distribution	9145-9151	Cost of Capital, Transport Fee, Cost Allocation, Adjustment Clause
TXU-Gas Distribution	9400	Cost of Service, Allocation, Rate Base, Cost of Capital, Rate Design
Westar Transmission Company	4892/5168	Cost of Capital, Cost of Service
Westar Transmission Company	5787	Cost of Capital, Revenue Requirement
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Texas Gas Service Company	10506	Cost of Capital

TEXAS WATER COMMISSION		
Southern Utilities Company	7371-R	Cost of Capital, Cost of Service

SCOTSBLUFF, NEBRASKA CITY COUNCIL		
K. N. Energy, Inc.		Cost of Capital

HOUSTON CITY COUNCIL		
Houston Lighting & Power Company		Forecasting

PUBLIC UTILITY REGULATION BOARD OF EL PASO, TEXAS		
Southern Union Gas Company		Cost of Capital

DISTRICT COURT CAMERON COUNTY, TEXAS		
City of San Benito, et. al. vs. PGE Gas Transmission et. al.	96-12-7404	Fairness Hearing

DISTRICT COURT HARRIS COUNTY, TEXAS		
City of Wharton, et al vs. Houston Lighting & Power	96-016613	Franchise fees

DISTRICT COURT TRAVIS COUNTY, TEXAS		
City of Round Rock, et al vs. Railroad Commission of Texas et al	GV 304,700	Mandamus

SOUTH DAYTONA, FLORIDA		
City of South Daytona v. Florida Power and Light	2008-30441-CICI	Stranded Costs

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Fuel and purchased power cost recovery clause with generating performance incentive factor	§	**Docket No. 150001-EI**

DIRECT TESTIMONY AND EXHIBITS
OF
DANIEL J. LAWTON

ON BEHALF OF THE OFFICE OF PUBLIC COUNSEL

SEPTEMBER 23, 2015

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 61
PARTY: OFFICE OF PUBLIC COUNSEL – (DIRECT)
DESCRIPTION: Daniel J. Lawton DJL-2

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DIRECT TESTIMONY

OF

DANIEL J. LAWTON

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 150001-EI

SECTION I: INTRODUCTION/BACKGROUND/SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Daniel J. Lawton. My business address is 12600 Hill Country Blvd, Suite R-275, Austin, Texas 78738.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I have been working in the utility consulting business as an economist since 1983. Consulting engagements have included electric utility load and revenue forecasting, cost of capital analyses, financial analyses, revenue requirements, fuel reviews, and cost of service reviews, and rate design analyses in litigated rate proceedings before federal, state and local regulatory authorities, and in court proceedings. I have worked with numerous municipal utilities developing electric rate cost of service studies for reviewing and setting rates, including fuel clause rates and reconciliations. In addition, I have a law practice based in Austin, Texas. My main areas of legal practice include administrative law representing municipalities in electric and gas rate proceedings and

other litigation and contract matters. I have included a brief description of my relevant educational background and professional work experience in my Exhibit ____ Schedule (DJL-1).

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN UTILITY RATE PROCEEDINGS?

A. Yes. I have previously filed testimony in Florida and a number of jurisdictions across the country. A list of cases where I have previously filed testimony is included in my Exhibit ____ Schedule (DJL-1).

Q. ON WHOSE BEHALF ARE YOU FILING TESTIMONY IN THIS PROCEEDING?

A. I am providing analyses and testimony related to fuel hedging on behalf of the Office of Public Counsel, State of Florida ("OPC"). I will review the Florida Power & Light Company ("FPL"), Tampa Electric Company ("TECO"), Duke Energy Florida ("DEF), and Gulf Power Company's ("Gulf"), collectively ("the Companies") annual fuel cost recovery filings related to fuel cost hedging.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to address some of the economic and regulatory policy issues surrounding the Companies' proposals to continue their natural gas financial hedging programs as described in their 2016 Risk Management Plans. I address the historical impacts of the Companies' hedging programs on

consumers and the potential impacts on consumers if the 2016 Risk Management Plans are approved by the Florida Public Service Commission ("Commission"). Another OPC witness, Tarik Noriega, will quantify the historical impacts of hedging on consumers.

Q. WHAT MATERIALS DID YOU REVIEW AND RELY ON FOR THIS TESTIMONY?

A. I have reviewed prior rate orders of the Commission, the Companies' various filings in Docket No. 150001-EI, the Companies' filings in prior dockets, discovery responses to various requests in this proceeding, along with other information available in the public domain. When relying on various sources, I have referenced such sources in my testimony and/or attached Schedules and included copies or summaries in my attached Schedules and/or work papers.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE REASONABLENESS OF CONTINUED FINANCIAL HEDGING.

A. My analysis leads me to conclude that the overall costs of the natural gas financial hedging programs exceed the benefits to consumers. Therefore, I recommend that, on a prospective basis, the proposed continuation of gas hedging activities should be ended as a mechanism to limit gas (fuel) price volatility, and that the 2016 Risk Management Plans proposed by the Companies regarding future financial hedging proposals should not be approved by the Commission for the following reasons:

1. There is significant doubt as to the benefits of fuel hedging given the historical, ongoing, and potential financial costs to consumers;

2. From 2009 to 2014, significant hedging losses were experienced in five of the six years; and current estimates by the Companies indicate 2015 to be another year of hedging losses, making it six out of the last seven years with hedging losses;

3. The amount of hedging losses or "costs" passed on to consumers in the form of higher-than-market price fuel costs has been substantial with hedging costs (or higher-than-market fuel costs) amounting to a staggering $2.5 billion between 2011 and the estimated 2015 year;

4. Natural gas markets in terms of gas production and market supply have changed substantially in recent years reducing the probability and extent of significant supply-side market disruption and also reducing natural gas price volatility relative to past years;

5. Regulatory authorities are recognizing the limitations of financial hedging in the changed natural gas markets; and

6. The current fuel factor design and mechanism in Florida already adequately mitigates fuel cost volatility without the need and cost risk of financial hedging.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR CONCLUSIONS.

A. Since the early 2000 time period, when gas markets experienced substantial volatility and price spikes for natural gas due to supply constraints along with adverse weather impacting natural gas demand, market conditions particularly the supply of natural gas have changed substantially. Annual gas production has grown dramatically and available gas reserves are well beyond forecasted levels from even ten years ago. As a result, price levels have declined substantially and price volatility is substantially reduced from past levels. Moreover, current forecasts of gas market prices indicate stable gas prices in the near-term, mid-term, and longer-term time horizon. The recent market experience since 2011 and the current market forecasts for natural gas all indicate that volatility is declining, natural gas prices are more stable, and the facts and circumstances that once supported natural gas hedging as a tool to limit price volatility are no longer present. Further, there are available, transparent, cost-free opportunities to limit price volatility impacts on consumers going forward through the fuel adjustment clause. Given the enormous lost-opportunity costs experienced by consumers in terms of overall fuel costs, and the potential for additional lost opportunities for lower gas costs under the status quo hedging and risk management plans, financial hedging of natural gas should be ended at this time.

For all the above reasons, I recommend the Commission deny the 2016 Risk Management Plans submitted by the Florida Companies and that financial hedging of natural gas should be discontinued.

SECTION II: SUMMARY OF ISSUES ADDRESSED

Q. WHAT ISSUES DO YOU ADDRESS WITH REGARD TO THE FLORIDA COMPANIES' PROPOSALS TO CONTINUE HEDGING NATURAL GAS PURCHASES THROUGH THE VARIOUS RISK MANAGEMENT PLANS?

A. I first provide a brief summary of the historical financial hedging position of the Florida Companies. OPC witness Noriega addresses the history of the fuel adjustment clause and hedging in his testimony, and the amount of historical hedging losses experienced. My analysis of the financial hedging history examines these historical results from a statistical and volatility metric perspective;

Second, I address the natural gas market changes that have impacted natural gas market supply, prices, and market volatility;

Third, I address how the natural gas market results, related to declining gas price volatility in recent years, are tied to market changes making financial hedging in natural gas less effective;

Fourth, I address how regulatory authorities around the country are beginning to recognize that financial hedging of natural gas is not beneficial to consumers; and

Fifth, I address how the existing fuel factor mechanism addresses price volatility issues. I also address previously proposed changes that, if adopted, address fuel price volatility without the unnecessary cost or risks of financial hedging.

These issues and topics are addressed in the following testimony to arrive at a recommendation in this case.

SECTION III: HISTORICAL OVERVIEW OF NATURAL GAS HEDGING

Q. BEFORE GETTING INTO THE HISTORICAL OVERVIEW OF HEDGING, PLEASE DESCRIBE AND DEFINE NATURAL GAS PRICE HEDGING.

A. Natural gas price hedging is an action or economic activity intended to reduce price fluctuations or volatility. Hedging accomplishes the goal of reducing price volatility by locking in the future price to be paid ahead of time rather than subjecting future fuel purchases to the day-to-day price changes in the market place. The simplest form is an action taken to insure against price volatility risk. A natural gas hedge can be a physical or financial hedge. An example of a hedge is the purchase of a future gas quantity at a fixed price. Thus, no matter what the future market price, this pre-purchased gas quantity is hedged or locked-in.

A hedge is analogous to an insurance policy that protects against future price changes and volatility. It is important to note that the hedged or locked-in price assured by the hedge may be higher or lower than the future gas market price at the time the commodity is needed and consumed. In other words, hedges are not designed to beat the future market prices. Instead, hedging programs are designed to lock down prices and avoid the day-to-day volatility in market prices. However, when the sole purpose is to mitigate price volatility, then there is no built-in ability to capture any of the benefits associated with declining fuel prices on the hedged portion of natural gas.

The Commission has previously provided guidance as to a definition of financial hedging as follows:

> Financial hedging is a term used to describe the purchase or sale of an exchange-traded futures or options contract with the specific intent of protecting an existing or anticipated physical market position from unexpected or adverse price fluctuations.[1]

Financial hedging of fuel purchases has been defined and employed in Florida as a tool in the fuel procurement process for a significant period of time.

Q. DO HEDGING PROGRAMS HAVE COSTS?

A. Yes. There are two types of hedging costs. First, there is the cost of running a hedging program in terms of labor of staff dedicated to implementing the hedging program. These hedging program costs are generally not large.

Second, there are opportunity costs associated with hedging. With the purchase and sale of various hedging instruments relative to ultimate market prices, there are opportunity costs (losses) when the market price settles lower than the hedged price, and benefits (savings or gains) when the market price settles higher than the hedged price. By locking in a future price through hedging instruments, consumers lose the benefit of lower market prices when the hedged or locked in price is lower than the market price. These hedged natural gas prices versus market prices are the key

[1] "Notice of Proposed Agency Action Order Finding Florida Power & Light Company Took Reasonable Steps To manage The Risks Associated With Changes In Natural Gas Prices For The Period March 1999 Through March 2001", Order No. PSC-02-0793-PAA-EI, issued June 11, 2002, in Docket No. 011605-EI, In re: Review of Investor-owned electric utilities' risk management policies and procedures, at 3.

opportunity costs associated with hedging that need to be evaluated when assessing the benefits and need of hedging future natural gas purchases.

As used in my testimony, "hedging cost" or "hedging loss" refers to these opportunity costs associated with hedging and not the costs to run or administer a Company's hedging program.

Q. DO THE DAILY NATURAL GAS PRICE CHANGES (PRICE VOLATILITY) DIRECTLY AND IMMEDIATELY IMPACT RATES PAID BY FLORIDA CONSUMERS?

A. No. The day-to-day changes in natural gas prices (price volatility) do not directly and immediately have an impact on the monthly rates consumers pay in their monthly electric bills. This is because of the manner in which the Commission establishes the annual fuel factor in the annual fuel adjustment clause proceeding (A/K/A "Fuel Docket"). The fuel portion of the utility bill is estimated annually based on projected sales of electricity, fuel quantities needed for electric generation, fuel prices, and prior over/under recoveries – all to establish a fuel factor to be applied to the kilowatt consumption of consumer bills. Once established by the Commission, the fuel factor stays in place until changed by the agency at some future date.

Fuel factors are reviewed and changed at least on an annual basis. A more frequent fuel factor review is also possible through what is referred to as a mid-course correction as discussed below.

The fuel factor mechanism in Florida is similar to what many regulatory jurisdictions employ regarding establishing tariffs for future unknown fuel costs, collecting fuel costs, and addressing material changes in fuel costs during the collection period.

While day-to-day changes in market fuel prices (price volatility) do not alter the fuel factor, the cumulative effect of unexpected changes in market prices could have the effect of creating the need for a mid-course correction in the fuel factor because the materiality threshold is met due to the unexpected price changes. In other words, if the current fuel factor is determined to materially over/under collect fuel costs, then the utility is required to notify the Commission. Depending on the circumstances surrounding the material recovery deficiency, a new fuel factor may be established and charged to consumers to address fuel cost recovery.

Thus, while changes in commodity price levels (up or down) certainly will affect future fuel factor calculations, there is no direct and immediate impact of this price fluctuation on consumers' rates while a fuel factor is in place. However, to the extent fuel price volatility creates a material change in fuel costs (generally 10% over/under recovery of fuel costs), then a mid-course correction in fuel charges could be required.

Q. IS THERE A HEDGING COST REASON OR CONSIDERATION FOR THE COMMISSION TO REVISIT HEDGING PROGRAMS?

A. Yes. In 2008, the Commission stated "Hedging program[s] are designed to assist in managing the impacts of fuel price volatility. Within any given calendar period, hedging can result in gains or losses. *Over time, gains and losses are expected to offset*

one another."[2] (emphasis added). Since 2008, high levels of losses or lost opportunities, related to lower market prices relative to the hedged payment that have been part of a continuing trend over time, have resulted and should raise a red flag concerning the continuation of the hedging program and the costs borne by customers. Regulatory authorities should expect to see some losses in hedging for some years and possibly most years given ongoing program costs and the fact that financial hedging, like insurance protection, for price stability is not free. However, large and prolonged hedging losses should signal a re-evaluation of hedging programs in order to stem the tide of losses and costs to consumers.

Q. PLEASE PROVIDE AN HISTORICAL OVERVIEW OF NATURAL GAS HEDGING COSTS TO CONSUMERS.

A. Historical hedging costs of the Companies are being addressed in the testimony of OPC witness Tarik Noriega. Also, a review of earlier year historical hedging in Florida has been addressed and described in the Commission Staff's review of "Fuel Procurement Hedging Practices of Florida's Investor-Owned Electric Utilities" at www.floridapsc.com/publications/pdf/electricgas/HedgingPracticesIOUs.pdf (June 2008). Since the Commission Staff's June 2008 analysis, the utility companies in Florida have collectively missed out on substantial lower gas cost opportunities due to fuel hedging activities required by their Risk Management Plans every year for 2009 through 2015, except in 2014. The following table summarizes the Companies' annual

[2] Order No. PSC-08-0030-FOF-EI, at 4, issued January 8, 2008, in Docket No. 070001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

hedging opportunity costs (losses) for 2011 through 2015[3]:

Table-1[4]

Historic Hedging Opportunity Costs to Florida Customers

YEAR	HEDGING OPPORTUNITY LOSSES
2011	($694,455,607)
2012	($1,117,525,079)
2013	($140,565,299)
2014	$106,424,864
2015	($646,050,220)
Total 2011-2015	($2,492,171,341)

The hedging activities of the Florida Companies have cost consumers in terms of higher-than-market fuel costs every year except 2014. More recent hedging activities (since 2011) show substantial and mounting losses associated with fuel-related opportunity costs as a result of financial hedging.

While recent hedged prices may be locked-in and are not as volatile as market prices, the question before the Commission is whether the cost of the price stability - that is,

[3] The 2015 projected loss data is based on the Florida utilities' estimates of hedging losses provided in response to OPC's First Set of Interrogatories to Duke, Gulf, and TECO No. 5; and OPC's Fourth Set of Interrogatories to FPL No. 29.
[4] The Hedging Opportunity Losses are taken from the Responses to OPC's First Set of Interrogatories to Duke No. 2, To Gulf No. 2, To TECO No. 2, and OPC's Fourth Set of Interrogatories to FPL No. 26.

the elimination of price volatility, which cost consumers about $2.5 billion in lost market opportunities and higher gas prices since 2011 - is justified. Given current gas markets and current projections the answer to the question is: No.

Prices in the natural gas markets are declining. Volatility in gas prices is declining. There is just no basis to conclude that consumers should be paying substantially higher-than-market prices for natural gas to limit volatility when market evidence indicates volatility is declining and eliminating the need for hedging. Moreover, what price volatility impacts on consumers remain in today's environment are already mitigated through the Commission's fuel clause mechanism without financial hedging and its associated costs and risk to consumers.

Q. YOU USE THE TERM PRICE VOLATILITY IN CONJUNCTION WITH YOUR DISCUSSION OF HEDGING. WHAT IS PRICE VOLATILITY?

A. Generally speaking, price volatility is a broad and relatively loosely defined term. Price volatility speaks to changes in market prices; however, the impact and degree of volatility on market participants can vary substantially depending upon the geographic market or time interval of prices examined. For example, hourly price changes are different from daily, weekly, monthly, or annually averaged price changes.

Given that price volatility is not a precisely defined term, the measurement of price volatility can be subject to different approaches. For example, price volatility can be measured based on changes in the absolute value of price changes. This measure is

what one finds each day in the business reporting of price changes in markets. Absolute energy average price changes showing rapid and/or unanticipated change reflect a volatile market.

Another measure of volatility is viewed in terms of return, or the change in price relative to a previous price. These return measures of volatility measure the percentage change in price rather than the absolute value price increment described above. Thus, a 10 percent change is the same whether measured from a $0.20 increase from $2.00 per MMBtu, or a $1.00 increase from $10.00 per MMBtu.

Q. DO PRIOR COMMISSION ORDERS HELP IN DEFINING FUEL PRICE VOLATILITY?

A. No. Volatility is only defined generically. For example, in the "Order Approving Resolution of Issues" the Commission's Order No. PSC-02-1484-FOF-EI, in Docket No. 011605-EI, dated October 30, 2002, the proposed resolution of issues states the following:

> Each investor-owned electric utility recognizes the importance of managing price volatility in the fuel and purchase power it purchases to provide electric service to its customers. Further, each investor-owned electric utility recognizes that the greater the proportion of a particular fuel or purchased power it relies upon to provide electric service to its customers, the greater the importance of managing price volatility associated with that energy source.[5]

[5] Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, In re: Review of investor-owned electric utilities' risk management policies and procedures, at Attachment A "Components of Proposed Resolution, paragraph 1.

Thus, while the Commission points out the importance and potential impact of price volatility on electric consumer rates, no general or specific approaches to identifying and/or measuring price volatility are provided.

Q. DO THE FLORIDA COMPANIES PROVIDE AN APPROACH TO CALCULATING PRICE VOLATILITY?

A. Yes. The following was provided by each of the Florida Companies regarding price volatility:

> FPL: Volatility, as it relates to fuel prices, is a statistical measure of the variation in prices over time. Historical volatility for natural gas is measured by taking the standard deviation of the historical, measured day-to-day percentage deviations of the forward curve.[6]
>
> TECO: Tampa Electric measures variability and/or volatility of fuel costs primarily through standard deviation. Standard deviation is a common, mathematically sound means for assessing the variation in a set of values relative to the mean of that set of values.[7]
>
> DEF: There are two general methods for estimating volatility. One involves calculating the standard deviation of changes in historical prices, and the other derives the implied volatility using market prices of traded options. The Company uses the latter approach which provides the Company with observed market volatility which is the volatility that is trading in the market at a point in time and the market's view of uncertainty in future prices.[8]
>
> Gulf: [Both] the variance and standard deviation of hedged and unhedged natural gas prices are calculated based on monthly values over a period of twelve months.[9]

[6] FPL response to OPC's 10th Set of Interrogatories, Interrogatory No. 115.
[7] TECO Response to OPC's 3rd Set of Interrogatories, Interrogatory No. 39.
[8] DEF response to OPC's 3rd Set of Interrogatories, Interrogatory No. 40.
[9] Gulf Response to OPC's 3rd Set of Interrogatories, Interrogatory No. 40.

While there are differences in each of the Company's volatility estimates, all measures use a mathematical measure of dispersion variance and/or standard deviation applied to historical prices or prices of traded options.

As I discuss below, my review and analysis examines historical volatility in natural gas markets employing standard deviation utilizing daily, monthly, and annual data. These analyses demonstrate that volatility, as a measure of changes in gas market prices, is declining which is consistent with the significant market supply changes in the natural gas markets resulting from increased shale development since approximately 2007 – 2008. These analyses also show that price volatility concerns arose in the early 2000 period, when price hedging was viewed as a necessary mechanism by regulatory authorities in Florida and around the country for controlling fuel price changes, are no longer necessary given natural gas market changes.

SECTION IV: FLORIDA COMPANIES' HISTORICAL AND FUTURE HEDGING

Q. PROVIDE AN OVERVIEW OF WHAT THE FLORIDA COMPANIES ARE PROPOSING WITH REGARD TO FUTURE NATURAL GAS HEDGING.

A. A review of each Company's Risk Management Plan indicates more of the same of what was done in the past. In other words, there is no substantial change in their approaches to hedging. However, one difference is the provision that FPL will now incorporate the Woodford Project as part of its overall natural gas hedged quantities. Historically, substantial quantities of the expected natural gas burn quantities for each Company have been hedged. DEF, Gulf, and TECO provided their historical

percentage of volume hedged to fuel consumed for the period 2002 to 2014.[10] Since 2010, these Companies have hedged from a low of 33% for Gulf in 2010 to a high of 72% for TECO in 2014. According to a recent news article, FPL hedges about 60% of its fuel purchases.[11] Despite incurring enormous hedging costs (losses) since 2011, no major changes are described or proposed in the 2016 utility hedging plans for the future.

The obvious problem with the Florida Companies' "more of the same" approach with regard to hedging is that such approaches have generated cumulative losses exceeding $1.8 billion for the period 2011 through 2014.[12] The recent 2015 hedging efforts are expected to produce additional opportunity costs to customers of approximately $646 million.[13] Continuing to implement the same hedging practices, without modification and despite the paradigm shift in the natural gas markets, are likely to bring consumers more of the same lost opportunities in terms of overall fuel costs.

Q. WHEN DID THE FLORIDA COMPANIES BEGIN NATURAL GAS HEDGING?

A. Based on a review of the discovery in this case, most risk management hedging efforts began in the 2001 to 2002 timeframe.[14] Given the starting date, my analyses of gas markets and volatility issues will cover the period 2000 through the present.

[10] See DEF's, Gulf's, and TECO's Responses to OPC's 5th Set of Interrogatories, Interrogatory No. 71.
[11] "FPL says customers to save more in 2016 from utility's efficiency push" by Susan Salisbury, Palm Beach Post, September 2, 2015, *available at* http://www.mypalmbeachpost.com/news/business/fpl-says-customers-to-save-more-in-2016-from-utili/nnXKW/. Note: FPL's actual historical percentage of volume natural gas hedged to fuel consumed is confidential. See FPL's Response to OPC's 13th Set of Interrogatories, Interrogatory No. 148.
[12] See Table 1.
[13] *Id.*
[14] See TECO Response to OPC 3rd Set of Interrogatories, Interrogatory No. 37, DEF Response to OPC 3rd Set of

Q. WHAT ARE THE STATED GOALS OF THE FLORIDA COMPANIES' HEDGING PROGRAMS?

A. Based on a review of the discovery in this case, most risk management hedging objectives are to reduce fuel price volatility over time and to provide a greater degree of fuel price certainty.[15] FPL also notes that the "… goal is to execute a well-managed, non-speculative hedging program that is not intended to reduce fuel costs paid over time, but rather reduce the variability or volatility in fuel costs paid by customers over time."[16] Thus, the overriding concern in the risk management hedging programs (at least for FPL) is to limit fuel price variability impacts (volatility) and not fuel costs. Given the Companies' fuel price variability concerns, a significant factor in the hedging evaluation to be considered is whether price volatility concerns and issues are as important today as they have been in the past. It is also important to consider ongoing losses and the impact to consumers of paying substantially higher prices for fuel costs, especially if limiting potential fuel price volatility provides diminished and declining benefit. For example, if natural gas markets have expanded gas supply and the probability of market disruption is decreased, making unexpected price changes and spikes less and less likely, it may not make much sense to incur hundreds of millions of dollars in hedging costs through higher-than-market, locked-in or hedged, fuel costs.

Interrogatories, Interrogatory No. 37, FPL Response to OPC 10th Set of Interrogatories, Interrogatory No. 113, and Gulf Response to OPC 3rd Set of Interrogatories, Interrogatory No. 37. *See also* Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, In re: Review of investor-owned electric utilities' risk management policies and procedures.

[15] See TECO Response to OPC 3rd Set of Interrogatories, Interrogatory No. 38, DEF Response to OPC 3rd Set of Interrogatories, Interrogatory No. 38, FPL Response to OPC 10th Set of Interrogatories, Interrogatory No. 114, and Gulf Response to OPC 3rd Set of Interrogatories, Interrogatory No. 38.

[16] See FPL Response to OPC 10th Set of Interrogatories, Interrogatory No. 114.

Q. HOW DO THE FLORIDA COMPANIES EVALUATE EXPECTED PRICE VOLATILITY EACH YEAR TO DETERMINE THE EXTENT AND LEVEL OF HEDGING IN THEIR RESPECTIVE RISK MANAGEMENT PROGRAMS?

A. The short answer is: there is no analysis or evaluation being done. Instead, at the highest levels, hedging programs are implemented to limit volatility without consideration of market changes and/or expectations.[17] For example, on the issue of considering some acceptable level of volatility, Gulf stated: "[n]o target measurement of past fuel price volatility has been established that would preclude the Company from financially hedging future natural gas prices."[18]

DEF addressed this same issue by stating:

> As the **Company cannot predict future prices or actual volatility levels, defining a level of volatility that is acceptable is not possible.** What is known is that **prices are constantly changing and thus by definition contain volatility. The purpose of DEF's hedging program is to reduce that volatility by locking in prices.** Additionally, given the continued growth in natural gas generation for the Company and the State of Florida, the current level of natural gas prices, and the significant portion that natural gas makes up of the Company's fuel cost, the Company believes that executing a hedging program over time is a prudent risk management activity to reduce price volatility and create greater fuel cost certainty for customers.[19] (emphasis added)

It is difficult to envision something being more automatic at the macro level than DEF's hedging program described above. Certainly, it is a fact that market prices for natural

[17] See generally TECO Response to OPC 3rd Set of Interrogatories, Interrogatory No. 41, DEF Response to OPC 3rd Set of Interrogatories, Interrogatory No. 41, FPL Response to OPC 10th Set of Interrogatories, Interrogatory No. 117, and Gulf Response to OPC 3rd Set of Interrogatories, Interrogatory No. 41.
[18] See Gulf Response to OPC 3rd Set of Interrogatories, Interrogatory No. 41.
[19] See DEF Response to OPC 3rd Set of Interrogatories, Interrogatory No. 41.

gas, like all markets, are constantly changing and, as such, subject to some level of volatility. Given that the stated goal of hedging appears to be to mitigate volatility, which by definition always exists, it appears the hedging programs continue no matter the effectiveness and no matter the cost to consumers. I have found no cost/benefit evaluations of the hedging programs in Florida. Instead, the sole stated goal is to mitigate price volatility.

Q. DO THE FLORIDA COMPANIES' HEDGING PROGRAMS ACCOMPLISH THE GOAL OF LIMITING NATURAL GAS PRICE VOLATILITY?

A. Yes, it is an automatic result. Just as daily price changes by definition create the certainty of daily price volatility, locking-in and fixing future prices, rather than relying on day-to-day market prices, automatically reduces volatility. However, the fact that the result is automatic does not necessarily mean it is wise to hedge, especially in light of the decreasing need to hedge and the increasing cost to consumers resulting from automatic hedging activities.

Q. DID DEF EVALUATE THE ECONOMIC IMPACT OF THE DEF's AUTOMOATIC HEDGING ACTIVITIES FOR THE 2010 THROUGH 2014 PERIOD?

A. DEF readily acknowledges the automatic results of hedging and states:

> The Company's hedging plan reduces the risk of future price movements for a percentage of its forecasted burns by executing fix[ed] prices over time. No formal evaluation is necessary to reach this conclusion because by definition fixed prices are no longer subject to future price movements and as a result volatility and fuel cost price risk

> have been mitigated. ... DEF's hedging activities do not attempt to outguess the market and may or may not result in net fuel cost savings.[20]

DEF readily admits that the results of its hedging program are automatic, and no consideration of whether hedging is necessary, or cost effective for consumers, is ever undertaken.

Further, DEF addresses the fact that it ignores cost effectiveness considerations by stating:

> ... the purpose of hedging is to reduce the variability or volatility of fuel costs paid by customers over time and hedging does not involve speculating or attempting to anticipate the most favorable point in time to place hedges. Moreover, it is recognized that hedging can result in significant lost opportunities for savings in fuel costs paid by customers, and to balance the goal of reducing customers' exposure to rising fuel prices against the goal of allowing customers to benefit from falling prices, the Commission has recognized that it is appropriate to hedge only a portion of the total expected volume of fuel purchases.[21]

Hedging has the singular purpose of limiting or reducing price volatility without regard as to whether volatility is high, low, increasing, or declining. For example, under the DEF approach, prices can be expected to decline substantially, yet according to DEF, for some reason volatility in the price decline must be addressed by hedging and locking in future prices, thus risking the declining fuel cost benefit to consumers.

Q. ARE THERE ANY LIMITATIONS ON HEDGING IN THE RISK MANAGEMENT PLANS YOU EVALUATED?

A. The only limitation on hedging is to hedge less than 100 percent; however, even the percentage to hedge does not appear to be supported by any market analysis. There is

[20] See DEF Response to OPC 3rd Set of Interrogatories, Interrogatory No. 47.
[21] *Id.*

no consideration of changes in the market or any evaluation of the cost of hedging on consumers. Instead, the goal is to mitigate volatility (whether volatility is a problem or not) and hedge less than 100 percent of fuel requirements to reduce the adverse impacts of lost fuel opportunity costs.

Q. DID TECO EVALUATE THE ECONOMIC IMPACT OF THE TECO HEDGING ACTIVITIES FOR THE 2010 THROUGH 2014 PERIOD?

A. Yes, but only in part. TECO provided the economic impact of its hedging by stating:

> For 2010 through 2014, financial hedging of natural gas prices has lowered the standard deviation from 19 percent for monthly NYMEX natural gas settlement prices to 18 percent for monthly-hedged natural gas prices.[22]

Absent from TECO's hedging evaluation of a one percent decline in volatility is the fact that TECO consumers lost about $150.9 million in lower fuel costs because of the hedges during the 2010 through 2014 period.[23] The effect of limiting volatility by one percent at a consumer cost of $150.9 million is never considered in deciding whether to hedge or even how much to hedge.

Q. HOW DOES FPL EVALUATE THE ECONOMIC IMPACT OF ITS HEDGING ACTIVITIES FOR THE 2010 THROUGH 2014 PERIOD?

A. In terms of natural gas price volatility reduction during the 2010-2014 period, FPL states:

> Through its hedging program, FPL locks in the price of a percentage of its projected natural gas requirements. Having done so, it is a mathematical certainty that the variability/volatility in fuel costs will be

[22] See TECO Response to OPC 3rd Set of Interrogatories, Interrogatory No. 47.
[23] See TECO Response to OPC's 1st Set of Interrogatories No. 2.

> reduced because the fixed price hedge replaces the floating market price for the volume that is hedged. Therefore, the price of the hedged volumes can no longer move with fluctuating market prices ...[24]

However, FPL does not address that the consumer cost of the mathematical certainty of reducing volatility reduction in natural gas prices, i.e. higher fuel cost resulting from hedging, cost FPL consumers about $1.450 billion over the 2010 to 2014 period.[25] Based upon this substantial amount of higher fuel costs alone, it is difficult to discern a consumer benefit from hedging in the period since 2010.

Q. EARLIER YOU DISCUSSED HOW THE FLORIDA COMPANIES HEDGE LESS THAN 100 PERCENT OF THEIR FUEL REQUIREMENTS IN RECOGNITION OF POTENTIAL LOST FUEL COST BENEFITS WHEN MARKET PRICES ARE DECLINING. DOES THAT FACT MAKE A DIFFERENCE IN THE HEDGING EVALUATION?

A. No. First, there is a great deal of room between 1 percent and 100 percent hedging and, unfortunately, there is no analysis or basis that I have determined, in how the ultimate hedging percentage is established. For example, when gas markets have shown declining volatility and increased production and reserve levels with lower overall price levels (as the market exists today), one would expect to see less hedging. However, the Florida Companies are hedging more than ever without regard to market conditions or limited hedging needs. Further, there is no incentive to cease hedging because there

[24] See FPL Response to OPC 10th Set of Interrogatories, Interrogatory No. 123.
[25] The Hedging Opportunity Losses are taken from the Responses to OPC's First Set of Interrogatories To FPL No. 26.

is virtually no risk of fuel cost disallowance for any hedging decision so long as the Companies follow their approved hedging plans.

SECTION V: ANALYSIS OF HISTORICAL PRICE VOLATILITY

Q. WHAT ISSUES DO YOU ADDRESS IN THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this part of my testimony is to review and summarize the historical volatility of the natural gas markets. The period covered by the Henry Hub database I employ is 1997 through July 2015. My general focus for this analysis is from January 2000 through July 2015. I address volatility and how it is measured along with the changes in volatility in the natural gas markets over time.

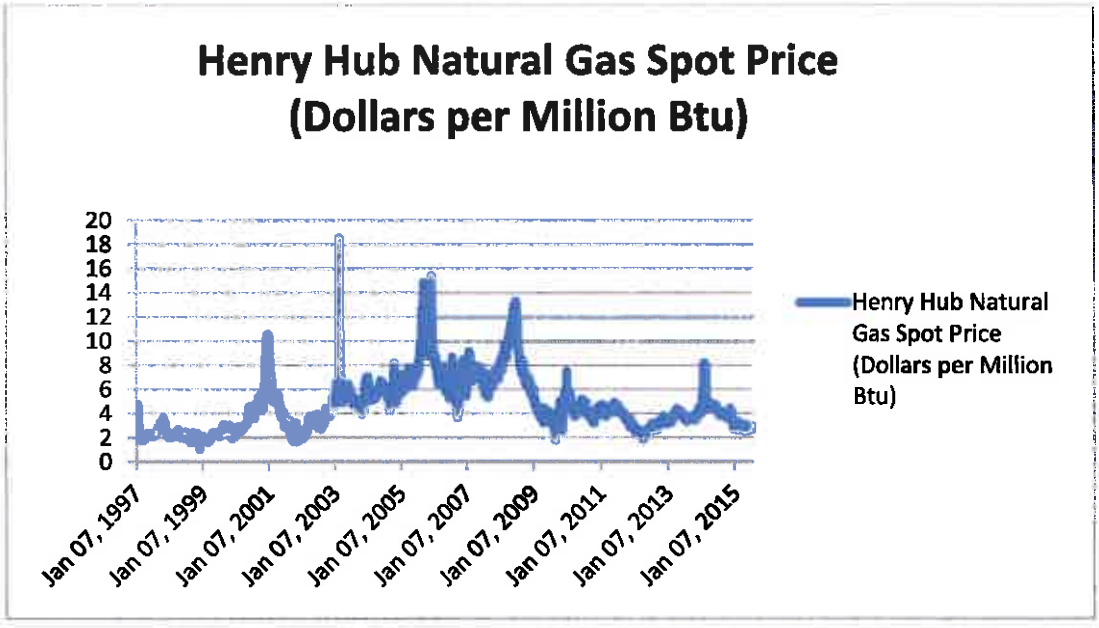
Q. PLEASE EXPLAIN HOW YOU MEASURE PRICE VOLATILITY FOR YOUR ANALYSIS.

A. My analysis of natural gas price volatility examined the changes in market prices for natural gas at the Henry Hub.[26] The data series of prices was extracted from the Energy Information Agency's ("EIA's") historical database and covered the period January 1, 1997 through July 31, 2015. The data examined over this time period consisted of daily, weekly, monthly, and annual natural gas price data. I have included in Table 2 below a graph of the Daily Henry Hub Spot Price for the period January 1997 through July 31, 2015.

[26] The Henry Hub pipeline is the pricing point for natural gas futures on the New York Mercantile Exchange (NYMEX). The settlement prices at the Henry Hub are used as benchmarks for the entire North American natural gas market.

The level of prices does not determine price volatility; rather, it is the degree of price variation one evaluates to determine price volatility. As shown in Table 2, from January 1, 1997 through July 31, 2015, the level of prices ranges from a high of over $18.00 to a low of under $2.00 per MMBtu, and the volatility changes substantially over time. Also, the trends in prices either increasing or decreasing do not necessarily indicate whether a market is volatile. Volatility is generally measured by the percent changes in day-to-day prices. A large price movement when prices are high may equate to the same volatility level as a smaller price movement when prices are at lower levels.

TABLE-2



Q. HAVE YOU REVIEWED ANY STUDIES THAT HAVE EVALUATED NATURAL GAS MARKET VOLATILITY?

A. Yes. One study that stands out is "*An Analysis of Price Volatility in Natural Gas Markets*" published by the EIA, Office of Oil and Gas in August 2007, which addresses gas market volatility in the January 1994 through December 2006 period. The purpose

of the EIA volatility study was to "… address whether [or not] natural gas prices have been more volatile in recent years …"[27] The EIA analysis found no increasing or decreasing trend in natural gas spot price volatility at the Henry Hub for the 1994 through 2006 period.[28]

For the analysis in this case, I utilize the same approaches for measuring volatility employed by EIA in their 1994 through 2006 volatility study. The goal of my review is to determine if there is a discernable trend in natural gas spot price volatility. If in fact a trend exists, that will be important information for the Commission to consider in terms of how fuel price hedging should be addressed in the future.

Q. HOW DID YOU MEASURE OR CALCULATE PRICE VOLATILITY FOR YOUR ANALYSIS?

A. To evaluate volatility trends, my analysis evaluated daily Henry Hub natural gas spot prices between January 1997 and July 31, 2015. The Henry Hub spot price data is available from the EIA at http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm. The Henry Hub is a primary trading location and, in my opinion, is representative of gas market prices that Florida companies encounter in the market.

Historical price volatility is defined as the standard deviation of the relative change in natural gas prices times a measure of trading days within the time period measured.[29]

[27] "*An Analysis of Price Volatility in Natural Gas Markets,*" Energy Information Administration, Office of Oil and Gas, (August 2007) at 2.
[28] *Id.*
[29] *Id.*at 3.

Viewed as a formula, natural gas price volatility is the standard deviation of price change, where price change is measured as the day-to-day price change (p_t / p_{t-1})[30] A natural log transformation of the day-to-day price change is where: $\Delta p_t = \ln(p_t / p_{t-1})$[31] This log normal volatility measurement is similar to the statistical measure employed by Morningstar in its historical measures of stock price volatility[32] To annualize the volatility result, the resulting standard deviation of the price change calculation was multiplied times the square root of the ratio of 252 trading days by the number of trading days for the period examined. For this analysis, annual and monthly periods were examined.[33] The number of trading days employed for these analyses is 252 days for the annual analysis.[34]

One could measure volatility in terms of measuring the standard deviation of daily percentage price changes $((p_t / p_{t-1})-1)$ or daily absolute price changes $(p_t - p_{t-1})$. The relative historical relationships will remain the same so long as the volatility metric employed is consistently applied.

Q. DOES THE COMMODITY PRICE LEVEL DETERMINE VOLATILITY?

A. No. Volatility is generally defined by the degree of price variation in the market. Neither the absolute level of price nor the trend or direction of price determines

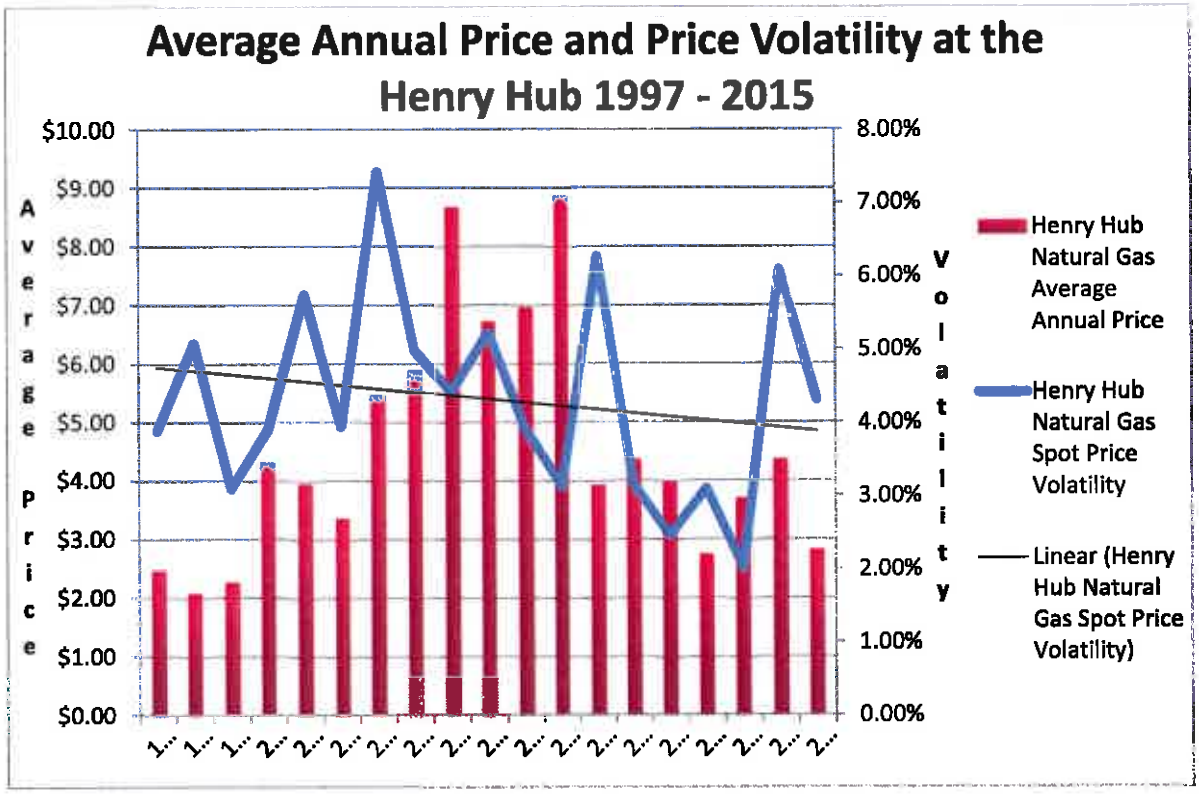
[30] Where p_t is today's price and p_{t-1} is the prior day price.
[31] "*An Analysis of Price Volatility in Natural Gas Markets,*" Energy Information Administration, Office of Oil and Gas, (August 2007) at 3-4.
[32] Morningstar Investment Glossary, Historical Volatility at http:/www.morningstar.com/InvGlossary/historical_volatility.aspx
[33] "*An Analysis of Price Volatility in Natural Gas Markets,*" Energy Information Administration, Office of Oil and Gas, (August 2007) at 3-4.
[34] *Id.* at 4.

volatility. Price volatility can be high or low when commodity prices are generally high, and price volatility can be equally high or low when commodity prices are low. Remember, volatility is a measure of change in the price of natural gas and not the actual price itself.

Q. PLEASE DESCRIBE YOUR ANNUAL PRICE VOLATILITY ANALYSIS AND THE RESULTS OF YOUR PRICE VOLATILITY CALCULATIONS ON THE NATURAL GAS MARKETS.

A. I have included in Schedule (DJL-2) the results of my annual volatility analysis of natural gas market price volatility for the period January 1997 through July 2015. The analysis demonstrates that volatility measure has declined by about 24 percent from the 2000 to 2010 period to the more recent 2011 to July 2015 period. The volatility trend is down, and average annual prices have declined 37.8 percent and are currently at some of the lowest levels in the 2000 to 2015 historical period. I have included in Table 3 a graphic depiction of average prices and price volatility measured on an annual basis over the 2000 to July 2015 time horizon. Schedule (DJL-2) also includes separate graphs of volatility and average price over the 2000 to 2015 period to capture the trends in each market variable.

TABLE-3



The declining trend in volatility and decreased levels of volatility are clearly discernable in the 2010 to 2015 time period. While 2014 is an outlier to this declining volatility trend; much of the 2014 price volatility is due to a few days in February and March 2014 reflecting extreme weather expectations (related to the polar vortex impacting much of the country). If the short-term, extreme weather event is removed, the 2014 price volatility would be consistent with the levels estimated for 2011, 2012, 2013, and 2015.

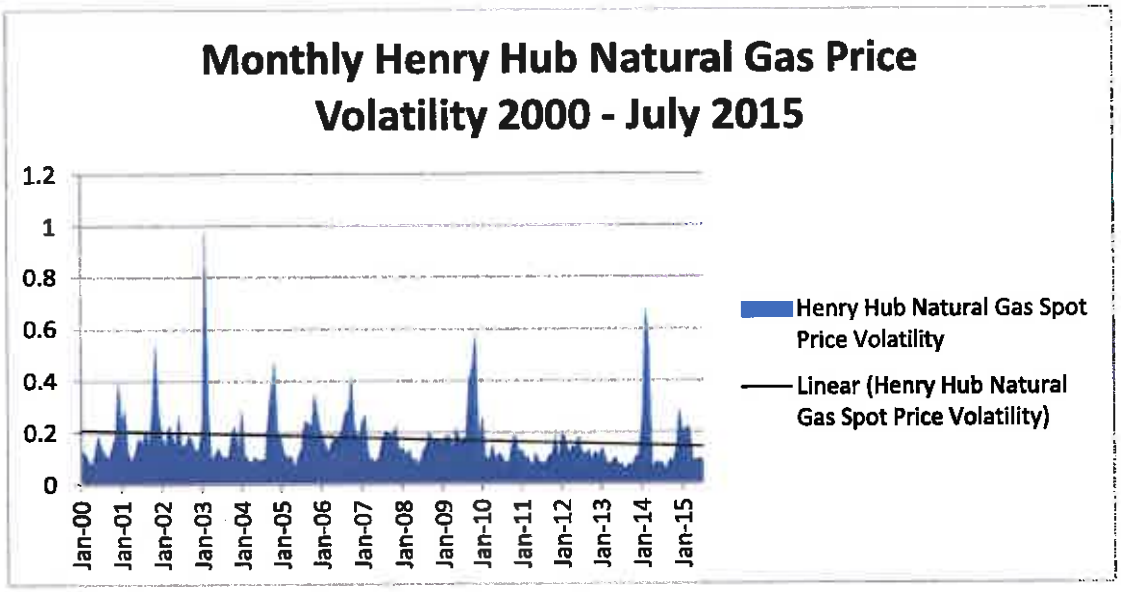
As discussed in the next Section of my testimony, the market changes from the supply side given expanded shale production and increased levels of reserves has led to decreased average annual prices and decreased levels of price volatility. Taking into

account the increases in supply and increases in natural gas storage, the potential for short-term supply disruptions is reduced, which results in lower prices and less price volatility. When I discuss the more recent EIA forecasts of the gas markets, I will address this natural gas supply side impact on price and volatility.

Q. PLEASE DESCRIBE YOUR MONTHLY PRICE VOLATILITY ANALYSIS AND THE RESULTS OF YOUR PRICE VOLATILITY CALCULATIONS ON THE NATURAL GAS MARKETS.

A. I have also included in Schedule (DJL-3) the results of the monthly volatility and average price analyses for the period January 2000 through July 2015. All the calculations employed the same data and formulas as the annual approach except that monthly volatility estimates were annualized. Volatility, on a monthly basis, has declined by over 28.0 percent from the 2000 – 2010 period to the more recent 2011 – July 2015 as shown in Schedule (DJL-3). The volatility trend is down and average monthly prices have declined 36.8 percent and are currently at some of the lowest levels in the 2000 – 2015 historical period. I have included in Table 4 below a graphic depiction of average prices and price volatility measured on a monthly basis over the 2000 to July 2015 time horizon.

TABLE-4



Similar to the results of the annual analysis, the monthly evaluation also shows price volatility is declining. For the period 2011 – 2015, the amount of price dispersion is much less than the earlier historical period. Again, the February 2014 period reflects an outlier event explained by a few days of abnormal weather events impacting much of the country simultaneously. Schedule (DJL-3) contains more detailed analyses of the historical data that also shows the declining volatility and natural gas price trend.

In my opinion, these trends related to declining volatility and price are the result of changes in the natural gas markets resulting from the increased gas supply, more stable/less volatile gas prices, and lower gas prices, all of which are less subject to intermittent supply disruptions.

Q. PLEASE DESCRIBE YOUR MONTHLY PRICE VOLATILITY ANALYSES CONTAINED IN SCHEDULES (DJL-4) THROUGH (DJL-8).

A. These analyses are similar to the monthly analysis of natural gas price volatility discussed in Schedule (DJL-3) above. The difference is that I broke down the 1997 to 2015 period into five periods to show added detail and changes over time in the markets. Schedule (DJL-4) covers the 1997 to 1999 historical period, which is generally a pre-hedging period. As demonstrated in Schedule (DJL-4), natural gas prices remained relatively low throughout the period. Also, price volatility was relatively low except for January 1997 and March through June of 1998.

Schedule (DJL-5) examines the period 2000 to 2002. This is the period where natural gas hedging was implemented in many jurisdictions around the country and in Florida. Price levels increased during 2000 with price spikes at the end of that year. Also, the general level of volatility increased at the end of 2000 continuing into 2001.

Schedule (DJL-6) addresses the monthly volatility and average price levels in the 2003 to 2006 period. Average monthly price levels are substantially higher than prior periods and trending up over the period. Natural gas price volatility levels and ranges have increased during this period as well.

Schedule (DJL-7) reflects the monthly volatility and average price levels in the 2007 to 2010 period. This period covers increased natural gas shale development and, while average price and volatility is generally the same as the 2003 to 2006 period shown in

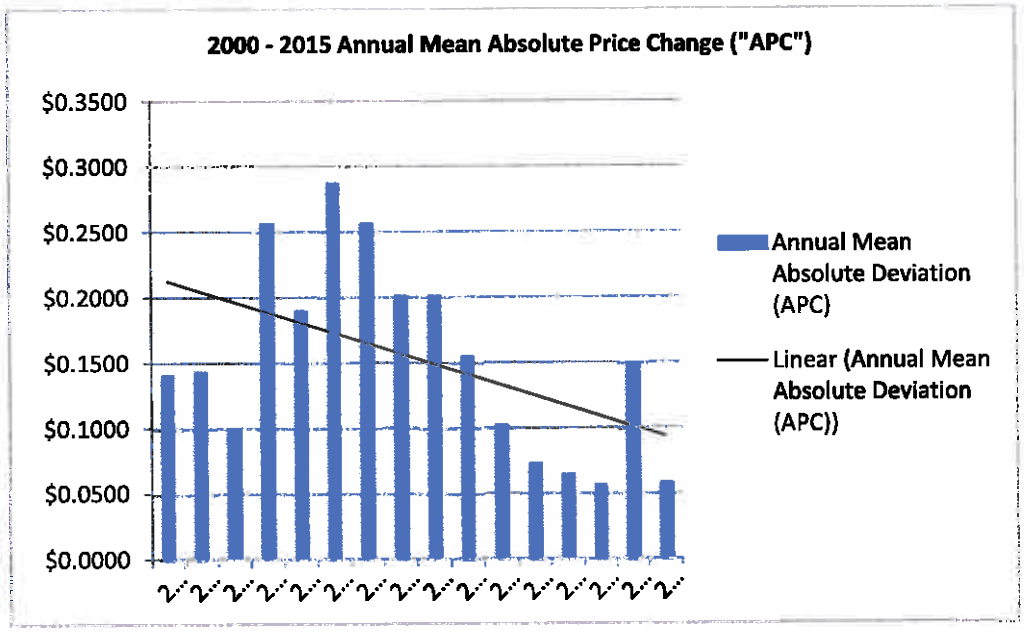
Schedule (DJL-6), the later months in Schedule (DJL-7) show lower price levels and a declining trend.

Schedule (DJL-8) covers the period 2011 through July 2015. In this period, average price levels are substantially below price levels since 2003. Further, the general level of volatility is well below all volatility levels experienced since 2000. The historical market data clearly demonstrates lower and declining average price levels and lower and declining price volatility levels.

Q. HAVE YOU PERFORMED ADDITIONAL ANALYSES OF GAS MARKET PRICES ADDRESSING VOLATILITY?

A. Yes. Below in Table 5 is an analysis of price variation considering the absolute value of the price changes. This analysis of absolute price change deviation differs from the previous analyses of percent changes in prices or volatility. The absolute price change ("APC") is determined by calculating the mean of the absolute day-to-day price movements at the Henry Hub. The APC was calculated for all days for the period 2000 – July 2015. Each year the annual average was calculated on the absolute value of price changes and the results are shown in Table 5 below:

TABLE-5



As shown in Table 5, the average absolute price change is less than 6 cents in 2013 and 2015, spiked in 2014 (due to extraordinary weather events), but overall shows a trend of a steady and steep decline from the early 2000's. I have included in Schedule (DJL-9) the underlying data and additional information related to the APC analysis. The bottom line is that the declining APC in market prices is consistent with the findings of a declining trend in gas price volatility discussed earlier.

Q. HAVE YOU REVIEWED ADDITIONAL EVIDENCE DEMONSTRATING DECLINING VOLATILITY OF GAS MARKET PRICES?

A. Yes. The findings of the declining average price deviation discussed above is reinforced by calculating the number of days in each calendar year that the absolute deviation in price from the previous day exceeds 25 cents, 50 cents, and $1 from 1997 through 2015.

Below in Table 6, I have included a tabulation of days where price deviations meet the criteria above for the period 2000 through July 2015:

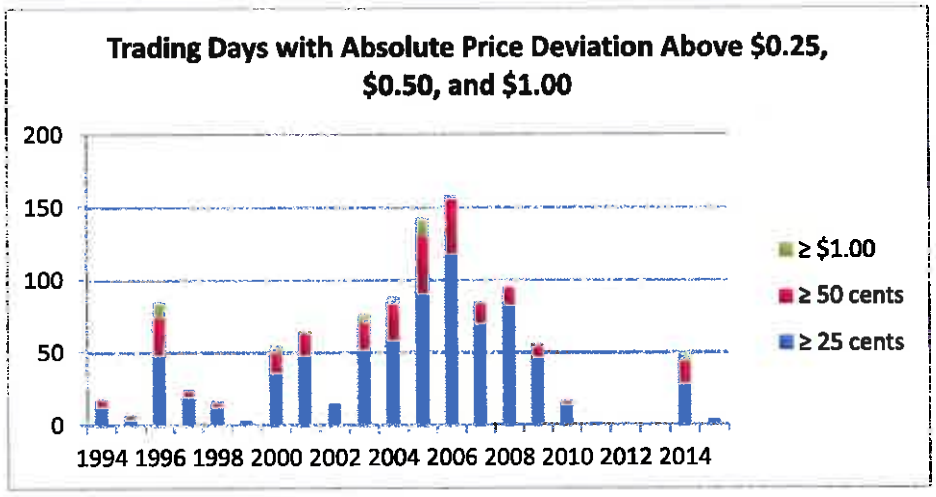
Table-6

Number of Trading Days with Absolute Price Deviations Meeting the Following Criteria			
YEAR	≥ 25 cents	≥ 50 cents	≥ $1.00
2000	35	14	6
2001	47	17	1
2002	15	0	0
2003	51	19	6
2004	58	25	5
2005	90	40	13
2006	117	39	2
2007	69	15	1
2008	82	13	0
2009	46	9	1
2010	13	3	1
2011	2	0	0
2012	1	0	0
2013	1	0	0
2014	28	15	7
2015	4	0	0

As shown in Table 6, since 2010 there are very few daily price movements that exceed 25 cents on a given day. Since 2011, there are no price movements that exceed 50 cents or $1.00 (except for the unusual events in 2014 discussed earlier). Given that the purpose of hedging, in my opinion, is to avoid **extreme price changes and price volatility**, Table 6 demonstrates extreme price changes are nonexistent since 2011 (except for the extraordinary events of 2014).

The raw data in Table 6 is summarized graphically in Table 7:

Table 7



As can be seen in Table 7 above, data in the years 2011, 2012, 2013, and 2015 barely register above zero, indicative of a substantial decline in large price movements.

Q. PLEASE SUMMARIZE YOUR EVALUATION OF HISTORICAL NATURAL GAS MARKET PRICES AND PRICE VOLATILITY.

A. The historical data demonstrates that natural gas market prices have generally declined to lower levels since 2011. More importantly, the historical data demonstrates that ***price volatility*** has substantially declined since 2011. The historical data demonstrates that the absolute level of price change has declined to lower levels relative to historic experiences. The size and frequency of average daily price changes has diminished to much lower levels demonstrating that price volatility has substantially declined.

Q. DOES THE FACT THAT THE HISTORICAL AND CURRENT TRENDS IN NATURAL GAS PRICES AND PRICE VOLATILITY ARE DECLINING MEAN THAT FUTURE PRICES AND PRICE VOLATILITY WILL CONTINUE TO DECLINE AND/OR REMAIN AT LOW LEVELS?

A. No. The fact that price levels and price volatility have declined does not necessarily mean that future price and volatility levels will remain low and/or continue to decline. Given that gas price levels and price volatility are driven by the supply and demand interaction in the market place, a review of the market and market expectations is important to make an assessment of what the future holds. Historically, short-term natural gas price levels and resulting volatility have been sensitive to short-run supply and/or demand shifts and disruptions. Due to the natural gas consumers' inability to fuel shift in the short run, supply and demand imbalances due to unexpected extreme weather or other demand disruption, combined with limited ability to expand short-run supply, have made gas markets significantly vulnerable to commodity price volatility. I discuss in the next section how market changes have substantially expanded the supply and availability of natural gas, leading to generally lower prices and decreased levels of volatility relative to the past.

SECTION VI: OVERVIEW OF CURRENT NATURAL GAS MARKETS

Q. HAVE ESTIMATES OF PROVED GAS RESERVES IN THE UNITED STATES INCREASED?

A. Yes. Proved reserves represent gas quantities that analyses show to be economically recoverable. Proved reserves have increased every year since 1999[35] The total natural gas proved reserves "… set a record of 354 trillion cubic feet ("Tcf") in 2013."[36] EIA's analysis indicates that "[m]ajor advances in natural gas exploration and production technologies has resulted in increased U.S. natural gas proved reserves."[37]

In terms of reserves, there are additional large volumes of natural gas referred to as "*undiscovered technically recoverable resources*."[38] Such resources are expected to exist, as geological formations are favorable despite the uncertainty of the specific locations. The EIA estimated that as of January 2012 the U.S. "had 1,932 Tcf of undiscovered, technically recoverable resources of dry natural gas."[39] That is about 65 years' worth of gas, assuming a consumption level of 30 Tcf per year. Obviously, the actual number of years of gas supply will depend on annual gas consumption, gas imports and/or exports, and net additions to gas supply reserves each year.

[35] "Natural Gas Explained", U.S. Energy Information Administration (February 2, 2015) at 1. URL: www.eia.gov/Energyexplained/index.cfm?page=natural_gas_reserves
[36] *Id.*
[37] *Id.*
[38] *Id.*
[39] *Id.*

Q. HAVE YOU REVIEWED THE FORECAST OF FUTURE NATURAL GAS MARKET PRICES AND SUPPLIES?

A. Yes. My first review examined the EIA Annual Energy Outlook 2011. This was the most current long-term forecast available to this Commission when the October 2011 Workshop reviewed hedging for Florida utilities. The EIA Annual Energy Outlook 2011 forecast estimated long-term growth (through 2035) in prices of 4.1%, production growth of 0.9%, reserves of 314 Tcf, and consumption levels growing through 2035 at 0.6%.[40]

The 2011 EIA forecast states the following regarding natural gas prospects in general and shale gas specifically:

> Unlike crude oil prices, natural gas prices do not return to the higher levels recorded before the 2007-2009 recession. … The large difference between crude oil and natural gas prices results in a shift in drilling towards shale formations with high concentrations of liquids.
>
> **Shale gas continues to have enormous potential**….[41] (emphasis added)

Now, a short four years later, the 2015 EIA forecast estimates long-term natural gas growth in prices of 4.4% (through 2035), production growth of 1.5% (through 2035), consumption levels growing through 2035 at 0.4%[42] and gas reserve levels of 345 Tcf.[43] The following Table 8 summarizes the comparison of the 2011 and 2015 EIA forecasts

[40] Annual Energy Outlook 2011, Energy Information Administration Table A1 p.115 and Table A13 & A14 pp. 142-143.
[41] *Id.* at 78-79.
[42] Annual Energy Outlook 2015, Energy Information Administration, Appendix A, Table A-1, The compound annual growth rate (CAGR) in nominal price of 4.4%, production 1.5%, and consumption 0.4% calculated between 2013 and 2035 from Appendix A, Table A-1.
[43] Id. Appendix A, Table A-14.

of natural gas prices, production, and reserves through 2030.

Table 8[44]

COMPARISON OF 2011 TO 2015 EIA NATURAL GAS ESTIMATES

	2011 EIA Forecast	2011 EIA Forecast	2015 EIA Forecast	2015 EIA Forecast
YEAR	FORECAST PRICE	PRODUCTION (Tcf)	FORECAST PRICE	PRODUCTION (Tcf)
2015	$5.09	23.01	$2.80 current price	24.40
2020	$6.10	24.04	$5.54	28.82
2025	$7.90	24.60	$6.72	30.51
2030	$9.28	25.75	$7.63	33.01

As demonstrated in the above chart, the EIA's current 2015 natural gas forecast estimates show increased production and lower prices in every year when compared to the 2011 EIA estimates. Generally, the stability and strength in the natural gas markets continue with the dramatic increases in production at lower price levels. Further, the declining prices estimates for natural gas are consistent with the historical record, showing declining prices, as discussed in Section III above. The natural gas market strength and maturity are also demonstrated by the continued increases in production in light of lower price forecast estimates.

[44] Annual Energy Outlook 2011, Energy Information Administration Table A1 p. 115-116, Annual Energy Outlook 2015, Energy Information Administration Tables A-14 and Table B-1. Note: Price value of $6.72 interpolated from 2020 and 2030 estimates.

Q. DO CURRENT FORECASTS OF NATURAL GAS MARKET PRICE, SUPPLY LEVELS, AND RESERVES SUGGEST THAT CONTINUATION OF FINANCIAL HEDGING WILL CONTINUE TO BE COSTLY TO FLORIDA CONSUMERS RELATIVE TO ANY POTENTIAL BENEFITS OF PRICE VOLATILITY REDUCTIONS?

A. Yes. As discussed above, current forecasts of natural gas markets indicate low and stable prices in the near term. These same forecasts also show plentiful supply and availability of natural gas and stable economic conditions. These forecasts indicate substantial changes (e.g., increased shale development) in natural gas markets have taken place since 2008 and 2011. Moreover, these current natural gas market forecasts demonstrate that the prior justifications and reasons for past natural gas hedging efforts (e.g., price volatility mitigation, threats to market supply, other factors influencing demand) are no longer available as reasons supporting the need to continue natural gas financial hedging activities. Given these current factors, it is more important than ever to consider the enormous opportunity costs incurred by consumers resulting from locking in fuel costs through hedging plans.

Q. IS THERE ADDITIONAL EVIDENCE THAT THE MARKET CHANGES YOU DISCUSSED HAVE HAD AN IMPACT ON NATURAL GAS PRICE VOLATILITY AND PRICE LEVELS?

A. Yes. A June 2013 Wall Street Journal article and analysis "*Volatility Evaporates in Natural-Gas Market*" describes and analyzes how price volatility has collapsed in the natural gas market. The article and analysis conclude that, "[b]ooming U.S. gas

production has led to fewer supply disruptions, smoothing out the big ups and downs that once dominated the market for natural gas."[45] The Wall Street Journal analysis also noted that day-to-day price moves have declined each year since 2005.[46] As discussed earlier, the historical analyses demonstrate how the statistical metrics for natural gas price volatility is declining significantly each and every year. A review of the historical data discussed in Section III demonstrates this declining price variability to be a fact.

SECTION VII: REGULATORY REVIEW OF FINANCIAL HEDGING

Q. HAS THIS COMMISSION REVIEWED THE FLORIDA COMPANIES' HEDGING PROGRAMS?

A. Yes, this Commission reviews the Florida Companies' hedging proposals and Risk Management Plans each year in the fuel docket.

The Commission specifically reviewed the natural gas financial hedging issues in an October 2011 Workshop Session ("Workshop").[47] As I understand, the purpose of the Workshop was to:

> ... look at ... with the additional shale gas production ... any other changes that are out there, do we need to relook at how we're doing or what we're doing at this point ...[48]

[45] "Volatility Evaporates in Natural-Gas Market," http://blogs.wsj.com/moneybeat/2013/06/06/volatility-evaporates-in-natural-gas-market/
[46] *Id.*
[47] New Issues In Hedging, Florida Public Service Commission, Undocketed Workshop, (October 4, 2011)
[48] Id. at 5:13-17 quoting Commissioner Balbis.

The Commission Staff further summarized the purpose of the Workshop:

> … this workshop is to discuss new information that may affect the hedging activities by the investor-owned utility companies. Today's topic for discussion include issues that affect natural gas price hedging since the issuance of Commission Order PSC-08-0667-PAA-EI on October 8, 2008. These topics include but are not limited to areas such as development of shale gas, natural gas price volatility, current state of the economy …[49]

Based on a review of the Workshop transcript, Mr. McCallister of Progress Energy (N/K/A DEF) proceeded to provide a joint investor-owned utility ("IOU") presentation addressing the Workshop topics.[50] Mr. McCallister's IOU presentation basically concluded that: "… developments in the natural gas markets do not warrant changes to the Commission's hedging policies and procedures that were established in 2008."[51]

The Companies' joint presentation addressed and emphasized growth in shale gas production.[52] The joint presentations also emphasized while "…natural gas prices and volatility have declined, it is impossible to predict to what magnitude circumstances may change and an increase in price and volatility."[53] Presented as examples of factors that could impact natural gas market output, prices, and price volatility were "[i]ncreased regulation of shale gas production,"[54] and the potential of LNG exports pressuring gas prices upwards.[55]

[49] *Id.* at 6: 2-10 quoting Mr. Franklin Commission Staff.
[50] *Id.* at 6:10-12.
[51] *Id.* at 7:10-12.
[52] *Id.*
[53] *Id.* at 22: 14-17.
[54] *Id.* at 22: 17-18.
[55] *Id.* at 22: 19-21.

The IOU joint presentation basically concluded that:

> … developments in the natural gas market do not warrant changes to the Commission's hedging policies and procedures that were established in 2008. And as we stand today, the IOUs continue to implement their hedging programs consistent with those policies and procedures.[56]

Since the 2011 Commission Hedging Workshop, the IOU hedging programs were left intact, and were implemented by the IOUs, which brings us to the main issue in today's fuel docket proceeding – Is it in the consumers' best interest for the utilities to continue to financially hedge natural gas?

Q. HAVE THE FLORIDA IOUs INCURRED SUBSTANTIAL ADDITIONAL ABOVE MARKET NATURAL GAS COSTS SINCE THE OCTOBER 2011 WORKSHOP?

A. Yes. As shown in Section III above, since the October 2011 Workshop, the IOU's financial hedging efforts have collectively cost customers approximately $2.5 billion in increased gas fuel costs. Moreover, the historical facts demonstrate that natural gas price market volatility is declining from historical levels. Thus, since the October 2011 Commission Workshop, the cost/benefit evaluation of the natural gas financial hedging programs indicates a substantial cost to consumers with questionable benefits.

Q. HAVE OTHER REGULATORY COMMISSIONS ADDRESSED THE FINANCIAL HEDGING ISSUE?

A. Yes, the Kentucky and Nevada utility commissions have addressed hedging.

[56] *Id.* at 22:23 through 23:2.

Q. WOULD YOU DESCRIBE THE SITUATION IN KENTUCKY?

A. Yes. In recent gas cases in the state of Kentucky, the Kentucky Public Service Commission ordered that the then existing financial hedging programs should not be extended.[57] In the case of Columbia Gas of Kentucky, Inc., a gas utility proceeding, the Kentucky Commission concluded the following regarding financial hedging natural gas prices:

> … the Commission finds that Columbia's hedging program should not be extended. **The Commission finds that current conditions and the outlook for future natural gas supplies and price are sufficiently different in 2014 from what they were in 2001 to allay our concern regarding the potential adverse impact of price volatility and extreme winter spikes on customer bills. We therefore conclude that it is no longer reasonable to impose the cost attendant to hedging, to the extent there is net cost rather than net savings, to be passed along to Columbia's customers as part of their gas cost.**…
>
> …
>
> While there is no guarantee that comparable [higher] prices and volatility will not recur, current projections from the United States Energy Information Administration's ("EIA") 2014 Annual Energy Outlook indicate prices not to exceed $8.00 per Mcf through 2040 using the reference case … More importantly with regard to volatility, the trend in price increases is projected to be gradual and steady in the long run.[58] (emphasis added)

The Kentucky Commission then issued an order that Columbia Gas "…cease hedging activities as of the date of this Order."[59]

[57] See for example *Application of Columbia Gas of Kentucky, Inc. to Extend its Gas Price Hedging Plan*, Case No. 2013-00354 Final Order at 4 (September 17, 2014), also see *Application of Atmos Energy Corporation For Continuation Of Its Hedging Program*, Case No. 2013-00421, Final Order at 4, (September 18, 2014), also see *Application Duke Energy Kentucky, Inc. To Implement A Hedging program to Mitigate Price Volatility In the Procurement Of Natural Gas*, Case No. 2015-00025, Final order at 4, (May 27, 2015).
[58] *Application of Columbia Gas of Kentucky, Inc. to Extend its Gas Price Hedging Plan*, Case No. 2013-00354 Final Order at 4 (September 17, 2014).
[59] *Id.* at 7.

Contemporaneous with the Columbia Gas hedging issues, the Kentucky Commission addressed the same issue involving another Kentucky gas utility, Atmos Energy Corporation ("Atmos").[60] In the Atmos case, the Kentucky Commission stated:

> Based on the evidence of record … the Commission finds that Atmos' hedging program should not be extended. … **The Commission finds that current conditions and the outlook for future natural gas supplies and prices are sufficiently different in 2014 from what they were in 2001 to allay our concern regarding the potential adverse impact of price volatility on customer bills. We therefore conclude that it is no longer reasonable to impose the cost attendant to hedging** ….[61] (emphasis added)

On or about March 27, 2015, the Kentucky Commission addressed the Duke Energy Kentucky, Inc.'s ("DEK's") January 28, 2015 request to continue its gas hedging program for its gas utility for an additional three years through March 2018.[62] DEK is a combined electric and gas utility. In that proceeding, the Kentucky Commission noted that DEK "… declared its willingness to discontinue seeking to extend its [hedging] program if the Commission did not want the program to be continued."[63] The Kentucky Commission went on to state:

> The Commission's concern with regard to the extension of gas cost hedging programs, ….**continued low and stable gas prices could obviate the need for hedging.** This was the conclusion we reached in those cases and is the conclusion we now reach in this case. …The **Commission finds that current conditions and the outlook for future natural gas supplies and prices are sufficiently different in 2015 from what they were in 2001 to allay our concern regarding the potential adverse impact of price volatility on customer bills.**[64] (emphasis added)

[60] *Application of Atmos Energy Corporation For Continuation Of Its Hedging Program*, Case No. 2013-00421, Final Order at 4, (September 18, 2014).
[61] *Id.* at 4-5.
[62] *Application Duke Energy Kentucky, Inc. To Implement A Hedging program to Mitigate Price Volatility In the Procurement Of Natural Gas*, Case No. 2015-00025, Final order at 1, (May 27, 2015).
[63] *Id.* at 3.
[64] *Id.* at 4.

The financial hedging programs for gas utility companies are no longer part of the fuel procurement process in Kentucky. Moreover, the current EIA forecasts demonstrate that gas market fuel supply is plentiful and gas price volatility is not the issue it once was.

Q. HAVE OTHER REGULATORY AUTHORITIES ENTERED RECENT ORDERS APPROVING THE CESSATION OF GAS HEDGING ACTIVITES?

A. Yes. On or about November 5, 2013, the Public Utilities Commission of Nevada ("Nevada Commission") approved a Stipulation of the parties that ceased the operation of the Southwest Gas hedging program.[65]

This approval of the Stipulation in the Southwest Gas case follows Nevada Commission Orders approving ending natural gas financial hedging for the two major electric utilities in Nevada.[66] There has been no financial gas hedging for these Nevada utility companies associated with natural gas procurement since the Nevada Commission issued the above referenced orders.

[65] Application of Southwest Gas Corporation to establish Base Tariff General rates, Unrecovered Gas Cost Expense rates, distribution shrinkage rates, commodity and reservation rates, and Renewable Energy Program rates, Before the Public Utilities Commission of Nevada, Docket No. 13-06006, Order approving Stipulation and Agreement at 3, 4, 13-14 (December 3, 2013).

[66] *See* Application of Sierra Pacific power Company d/b/a NV Energy for approval of its 2011-2013 Triennial Integrated Resource Plan, Docket No. 10-07003 (October 20, 2010), Compliance Order approving Amended and Re-stated Phase II (Energy Supply Plan) Stipulation at 4, 10-11, paragraph 10((a)-(g). *Also see* Application of Nevada Power Company d/b/a NV Energy for approval of its Energy Supply Plan Update for 2011-2012, Docket No. 10-09003, Order approving Stipulation at 2 (December 16, 2010); *See* Stipulation at 2-3, paragraph 1 (a)-(f).

Q. ARE YOU AWARE OF OTHER REGULATORY AUTHORITIES THAT DO NOT ALLOW FINANCIAL HEDGING IN THE NATURAL GAS PROCUREMENT PROCESS?

A. Yes. The Public Utility Commission of Texas historically has not authorized the regulated fully integrated electric utilities in areas outside of the Electric Reliability Council of Texas to employ financial hedging in the fuel procurement activities of the utility. The Railroad Commission of Texas, the regulatory authority charged with regulating gas utility companies in Texas has not pre-approved a gas utility company including expenses of financial hedges (including the increased expense of an out of money hedge) from gas or fuel adjustment clauses.[67] CenterPoint Energy Texas has elected to not employ financial hedging as a fuel procurement strategy.

It is true that most regulatory authorities authorize utility companies to employ some form of financial hedging in fuel procurement. However, those regulatory authorities which have recently taken up and ruled on this financial hedging question (like Kentucky and Nevada) have concluded that, given current gas market conditions and forecasts, there is no need for financial hedging in the gas procurement process.

Q. HAVE ADDITIONAL UTILITIES CONSIDERED THE NATURAL GAS MARKET CHANGES AND SUSPENDED HEDGING ACTIVITIES?

A. Yes. Colorado Springs Utilities is an example of a utility that in 2009 considered

[67] Statement of Intent of CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex and CenterPoint Energy Texas Gas To Increase rates On A Division-Wide Basis In The Houston Division, Railroad Commission of Texas, Gas Utilities docket No. 9902 (Consolidated), Final Order at 12, FoF 103, (February 23, 2010).

declining gas market costs and reviewed the merits of its hedging program, and in 2010 reduced the volumes and lengths of its hedges. Subsequently, after added market review and the recognition of gas market stability, Colorado Springs Utilities suspended all hedging in 2011, allowing its hedged supply contracts to expire in 2013.[68]

Q. IN YOUR OPINION, HAS THE NATURAL GAS MARKET SUBSTANTIALLY CHANGED SINCE THE FLORIDA COMMISSION'S 2011 FUEL HEDGING WORKSHOP?

A. Yes. As outlined in the Kentucky Commission Orders discussed earlier and shown in the analysis presented in my testimony, the natural gas markets have changed substantially over the past few years. The recent and current EIA forecasts show that natural gas production has substantially increased, probable and recoverable gas reserves for the future have increased substantially, forward estimates of natural gas prices have declined and become more stable, and price volatility has declined. Based on these factors, some regulatory authorities and utilities have concluded financial hedging is no longer necessary and moreover is no longer worth the risks or costs associated with financial hedging.

[68] Colorado Springs Utilities web page "Natural gas hedging program," www.csu.org/Pages/nghedging.aspx

SECTION VIII: AN ALTERNATIVE APPROACH TO PRICE VOLATILITY

Q. WHAT ISSUE(S) ARE YOU ADDRESSING IN THIS SECTION OF YOUR TESTIMONY?

A. The issues addressed in this Section of my testimony consider – in light of recent historical events in the natural gas markets with low natural gas price volatility, stable markets with limited disruptions, increased supply and growing natural gas reserves, and stable gas prices – what alternatives to financial gas hedging are available to address gas price volatility?

Q. HAVE ANY OF THE FLORIDA COMPANIES PREVIOUSLY PROPOSED ALTERNATIVES TO FINANCIAL HEDGING THAT WOULD ADDRESS FUEL PRICE VOLATILITY IMPACTS ON CONSUMERS?

A. Yes. In 2008, FPL proposed a volatility mitigation mechanism ("VMM") as an alternative to FPL's financial and physical fuel price hedging programs.[69] FPL later withdrew its request for a VMM and proposed hedging guidelines to govern the regulatory risk associated with its prior hedging program.[70] In its VMM proposal, FPL noted concerns related to asymmetric risks and rewards under FPL's hedging program.[71] FPL stated "… hedging the prices FPL pays for fuel, that is not necessarily the only or best approach."[72] FPL went on to state:

> FPL has concluded that the volatility in customer fuel charges can be mitigated almost as effectively as it has under FPL's current hedging

[69] Notice of Proposed Agency Action Order Clarifying Hedging Order And Providing Guidelines, Docket No. 080001-EI (October 2008) at 2.
[70] *Id.* at 3.
[71] Petition of Florida Power & Light for Approval of Improved Volatility Mitigation Mechanism, Docket No. 080001-EI (January 31, 2008) at 4.
[72] *Id.* at 7.

> program, by collecting under-recoveries of unhedged fuel costs over two years instead of one year … other aspects of the fuel clause would continue to work as they do currently.[73]

In terms of benefits of the VMM versus hedging, FPL noted the following: (i) FPL customers would avoid transaction costs associated with hedging, (ii) FPL customers would no longer pay risk premiums for fuel costs, (iii) deferred two-year fuel under-recoveries are financed at the low cost commercial paper interest rate; (iv) over-recoveries would flow back to FPL customers over one-year per the fuel rule; and (v) more opportunities for FPL customers to benefit promptly and completely from short-term price declines.[74]

Given the substantial changes in the natural gas markets regarding price, production, supply, and overall market stability, and given current forecasts of stable natural gas markets, and given the enormous customer higher-than-market fuel opportunity costs experienced since 2011, an alternative such as the FPL proposed VMM in 2008 is better than the *status quo* automatic hedging required by the Companies' Risk Management Plans.

Each year, the Commission reviews fuel costs and determines the appropriate amount of over/(under) fuel recovery. However, to the extent the Commission determines a large or material under-recovery of fuel costs has occurred, the Commission *in its regulatory discretion* can determine, without formally adopting FPL's 2008 VMM

[73] *Id.* at 7.
[74] *Id.* at 8-9.

proposal, whether a large under-recovery should be recovered over a one-year or longer period. Such an efficient, rational approach curbs the impact of price volatility on customers without the negative impacts of financial hedging.

Q. ARE YOU RECOMMENDING THAT THE COMMISSION ADOPT FPL'S 2008 VMM PROPOSAL OR A SIMILAR MECHANISIM?

A. No. I am recommending that the Commission deny approval of the Companies' 2016 Risk Management Plans, and order the Companies to discontinue financial hedging of natural gas.

SECTION IX: CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING NATURAL GAS FINANCIAL HEDGING.

A. Since this Commission's first order on hedging in 2002, natural gas markets have changed substantially. Natural gas prices, production, and supply are not as volatile as was experienced in the early 2000 time frame. Current gas market forecasts do not estimate volatile markets, but instead predict increased production at lower prices than earlier forecasts. Historical evidence since 2000 shows volatility in the gas markets to be declining. The historical cost of hedging in terms of paying higher-than-market prices for fuel has been staggering to Florida consumers for the past 12 years. A fair balancing of the declining volatility and declining hedging benefits to consumers against the substantial costs of hedging suggest that the cost/benefit assessment does not support future hedging. For all of the above reasons, I recommend that the Companies' proposed financial hedging plans not be approved and that financial

hedging of natural gas should be discontinued on a going-forward basis. If circumstances change substantially, hedging can be visited again in the future.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

DANIEL J. LAWTON
B.A. ECONOMICS, MERRIMACK COLLEGE
M.A. ECONOMICS, TUFTS UNIVERSITY

Prior to beginning his own consulting practice Diversified Utility Consultants, Inc., in 1986 where he practiced as a firm principal through December 31, 2005, Mr. Lawton had been in the utility consulting business with a national engineering and consulting firm. In addition, Mr. Lawton has been employed as a senior analyst and statistical analyst with the Department of Public Service in Minnesota. Prior to Mr. Lawton's involvement in utility regulation and consulting he taught economics, econometrics, statistics and computer science at Doane College.

Mr. Lawton has conducted numerous revenue requirements, fuel reconciliation reviews, financial, and cost of capital studies on electric, gas and telephone utilities for various interveners before local, state and federal regulatory bodies. In addition, Mr. Lawton has provided studies, analyses, and expert testimony on statistics, econometrics, accounting, forecasting, and cost of service issues. Other projects in which Mr. Lawton has been involved include rate design and analyses, prudence analyses, fuel cost reviews and regulatory policy issues for electric, gas and telephone utilities. Mr. Lawton has developed software systems, databases and management systems for cost of service analyses.

Mr. Lawton has developed and numerous forecasts of energy and demand used for utility generation expansion studies as well as municipal financing. Mr. Lawton has represented numerous municipalities as a negotiator in utility related matters. Such negotiations ranges from the settlement of electric rate cases to the negotiation of provisions in purchase power contracts.

In addition to rate consulting work Mr. Lawton through the Lawton Law Firm represents numerous municipalities in Texas before regulatory authorities in electric and gas proceedings. Mr. Lawton also represents municipalities in various contract and franchise matters involving gas and electric utility matters.

A list of cases in which Mr. Lawton has provided testimony is attached.

UTILITY RATE PROCEEDINGS IN WHICH TESTIMONY HAS BEEN PRESENTED BY DANIEL J. LAWTON

JURISDICTION/COMPANY	DOCKET NO.	TESTIMONY TOPIC
ALASKA REGULATORY COMMISSION		
Beluga Pipe Line Company Municipal Light & Power Enstar Natural Gas Co.	P-04-81 U-13-184 U-14-111	Cost of Capital Cost of Capital Cost of Capital
PUBLIC UTILITIES COMMISSION OF CALIFORNIA		
Southern California Edison	12-0415	Cost of Capital
San Diego Gas and Electric	12-0416	Cost of Capital
Southern California Gas	12-0417	Cost of Capital
Pacific Gas and Electric	12-0418	Cost of Capital
GEORGIA PUBLIC SERVICE COMMISSION		
Georgia Power Co.	25060-U	Cost of Capital
FEDERAL ENERGY REGULATORY COMMISSION		
Alabama Power Company	ER83-369-000	Cost of Capital
Arizona Public Service Company	ER84-450-000	Cost of Capital
Florida Power & Light	EL83-24-000	Cost Allocation, Rate Design
Florida Power & Light	ER84-379-000	Cost of Capital, Rate Design, Cost of Service
Southern California Edison	ER82-427-000	Forecasting

LOUISIANA PUBLIC SERVICE COMMISSION		
Louisiana Power & Light	U-15684	Cost of Capital, Depreciation
Louisiana Power & Light	U-16518	Interim Rate Relief
Louisiana Power & Light	U-16945	Nuclear Prudence, Cost of Service

MARYLAND PUBLIC SERVICE COMMISSION		
Baltimore Gas and Electric Company	9173	Financial
Baltimore Gas and Electric Company	9326	Financial

MINNESOTA PUBLIC UTILITIES COMMISSION		
Continental Telephone	P407/GR-81-700	Cost of Capital
Interstate Power Co.	E001/GR-81-345	Financial
Montana Dakota Utilities	G009/GR-81-448	Financial, Cost of Capital
New ULM Telephone Company	P419/GR81767	Financial
Norman County Telephone	P420/GR-81-230	Rate Design, Cost of Capital
Northern States Power	G002/GR80556	Statistical Forecasting, Cost of Capital
Northwestern Bell	P421/GR80911	Rate Design, Forecasting

MISSUORI PUBLIC SERVICE COMMISSION		
Missouri Gas Energy	GR-2009-0355	Financial
Ameren UE	ER-2010-0036	Financial

FLORIDA PUBLIC SERVICE COMMISSION		
Progress Energy	070052-EI	Cost Recovery
Florida Power and Light	080677-EI	Financial
Florida Power and Light	090130-EI	Depreciation
Progress Energy	090079-EI	Depreciation
Florida Power and Light	120015-EI	Financial Metrics
Florida Power and Light	140001-EI	Economic and Regulatory Policy Issues

NORTH CAROLINA UTILITIES COMMISSION		
North Carolina Natural Gas	G-21, Sub 235	Forecasting, Cost of Capital, Cost of Service

OKLAHOMA PUBLIC SERVICE COMMISSION		
Arkansas Oklahoma Gas Corporation	200300088	Cost of Capital
Public Service Company of Oklahoma	200600285	Cost of Capital
Public Service Company of Oklahoma	200800144	Cost of Capital
Public Service Company of Oklahoma	201200054	Financial and Earnings Related

PUBLIC SERVICE COMMISSION OF INDIANA		
Kokomo Gas & Fuel Company	38096	Cost of Capital

PUBLIC UTILITY COMMISSION OF NEVADA		
Nevada Bell	99-9017	Cost of Capital
Nevada Power Company	99-4005	Cost of Capital
Sierra Pacific Power Company	99-4002	Cost of Capital
Nevada Power Company	08-12002	Cost of Capital
Southwest Gas Corporation	09-04003	Cost of Capital
Sierra Pacific Power Company	10-06001 & 10-06002	Cost of Capital & Financial
Nevada Power Co. and Sierra Pacific Power Co.	11-06006 11-06007 11-06008	Cost of Capital
Southwest Gas Corp.	12-04005	Cost of Capital
Sierra Power Company	13-06002 13-06003 13-06003	Cost of Capital
NV Energy & MidAmerican Energy Holdings Co.	13-07021	Merger and Public Interest Financial

PUBLIC SERVICE COMMISSION OF UTAH		
PacifiCorp	04-035-42	Cost of Capital
Rocky Mountain Power	08-035-38	Cost of Capital
Rocky Mountain Power	09-035-23	Cost of Capital
Rocky Mountain Power	10-035-124	Cost of Capital
Rocky Mountain Power	11-035-200	Cost of Capital

Questar Gas Company	13-057-05	Cost of Capital
Rocky Mountain Power	13-035-184	Cost of Capital

SOUTH CAROLINA PUBLIC SERVICE COMMISSION		
Piedmont Municipal Power	82-352-E	Forecasting

PUBLIC UTILITY COMMISSION OF TEXAS		
Central Power & Light Company	6375	Cost of Capital, Financial Integrity
Central Power & Light Company	9561	Cost of Capital, Revenue Requirements
Central Power & Light Company	7560	Deferred Accounting
Central Power & Light Company	8646	Rate Design, Excess Capacity
Central Power & Light Company	12820	STP Adj. Cost of Capital, Post Test-year adjustments, Rate Case Expenses
Central Power & Light Company	14965	Salary & Wage Exp., Self-Ins. Reserve, Plant Held for Future use, Post Test Year Adjustments, Demand Side Management, Rate Case Exp.
Central Power & Light Company	21528	Securitization of Regulatory Assets
El Paso Electric Company	9945	Cost of Capital, Revenue Requirements, Decommissioning Funding
El Paso Electric Company	12700	Cost of Capital, Rate Moderation Plan, CWIP, Rate Case Expenses
Entergy Gulf States Incorporated	16705	Cost of Service, Rate Base, Revenues, Cost of Capital, Quality of Service
Entergy Gulf States Incorporated	21111	Cost Allocation
Entergy Gulf States Incorporated	21984	Unbundling
Entergy Gulf States Incorporated	22344	Capital Structure

Entergy Gulf States Incorporated	22356	Unbundling
Entergy Gulf States Incorporated	24336	Price to Beat
Gulf States Utilities Company	5560	Cost of Service
Gulf States Utilities Company	6525	Cost of Capital, Financial Integrity
Gulf States Utilities Company	6755/7195	Cost of Service, Cost of Capital, Excess Capacity
Gulf States Utilities Company	8702	Deferred Accounting, Cost of Capital, Cost of Service
Gulf States Utilities Company	10894	Affiliate Transaction
Gulf States Utilities Company	11793	Section 63, Affiliate Transaction
Gulf States Utilities Company	12852	Deferred acctng., self-Ins. reserve, contra AFUDC adj., River Bend Plant specifically assignable to Louisiana, River Bend Decomm., Cost of Capital, Financial Integrity, Cost of Service, Rate Case Expenses
GTE Southwest, Inc.	15332	Rate Case Expenses
Houston Lighting & Power	6765	Forecasting
Houston Lighting & Power	18465	Stranded costs
Lower Colorado River Authority	8400	Debt Service Coverage, Rate Design
Southwestern Electric Power Company	5301	Cost of Service
Southwestern Electric Power Company	4628	Rate Design, Financial Forecasting
Southwestern Electric Power Company	24449	Price to Beat Fuel Factor
Southwestern Bell Telephone Company	8585	Yellow Pages
Southwestern Bell Telephone Company	18509	Rate Group Re-Classification
Southwestern Public Service Company	13456	Interruptible Rates

Southwestern Public Service Company	11520	Cost of Capital
Southwestern Public Service Company	14174	Fuel Reconciliation
Southwestern Public Service Company	14499	TUCO Acquisition
Southwestern Public Service Company	19512	Fuel Reconciliation
Texas-New Mexico Power Company	9491	Cost of Capital, Revenue Requirements, Prudence
Texas-New Mexico Power Company	10200	Prudence
Texas-New Mexico Power Company	17751	Rate Case Expenses
Texas-New Mexico Power Company	21112	Acquisition risks/merger benefits
Texas Utilities Electric Company	9300	Cost of Service, Cost of Capital
Texas Utilities Electric Company	11735	Revenue Requirements
TXU Electric Company	21527	Securitization of Regulatory Assets
West Texas Utilities Company	7510	Cost of Capital, Cost of Service
West Texas Utilities Company	13369	Rate Design

RAILROAD COMMISSION OF TEXAS		
Energas Company	5793	Cost of Capital
Energas Company	8205	Cost of Capital
Energas Company	9002-9135	Cost of Capital, Revenues, Allocation
Lone Star Gas Company	8664	Rate Design, Cost of Capital, Accumulated Depr. & DFIT, Rate Case Exp.
Lone Star Gas Company-Transmission	8935	Implementation of Billing Cycle Adjustment
Southern Union Gas Company	6968	Rate Relief

Southern Union Gas Company	8878	Test Year Revenues, Joint and Common Costs
Texas Gas Service Company	9465	Cost of Capital, Cost of Service, Allocation
TXU Lone Star Pipeline	8976	Cost of Capital, Capital Structure
TXU-Gas Distribution	9145-9151	Cost of Capital, Transport Fee, Cost Allocation, Adjustment Clause
TXU-Gas Distribution	9400	Cost of Service, Allocation, Rate Base, Cost of Capital, Rate Design
Westar Transmission Company	4892/5168	Cost of Capital, Cost of Service
Westar Transmission Company	5787	Cost of Capital, Revenue Requirement
Atmos	10000	Cost of Capital

TEXAS WATER COMMISSION		
Southern Utilities Company	7371-R	Cost of Capital, Cost of Service

SCOTSBLUFF, NEBRASKA CITY COUNCIL		
K. N. Energy, Inc.		Cost of Capital

HOUSTON CITY COUNCIL		
Houston Lighting & Power Company		Forecasting

PUBLIC UTILITY REGULATION BOARD OF EL PASO, TEXAS		
Southern Union Gas Company		Cost of Capital

DISTRICT COURT CAMERON COUNTY, TEXAS		
City of San Benito, et. al. vs. PGE Gas Transmission et. al.	96-12-7404	Fairness Hearing

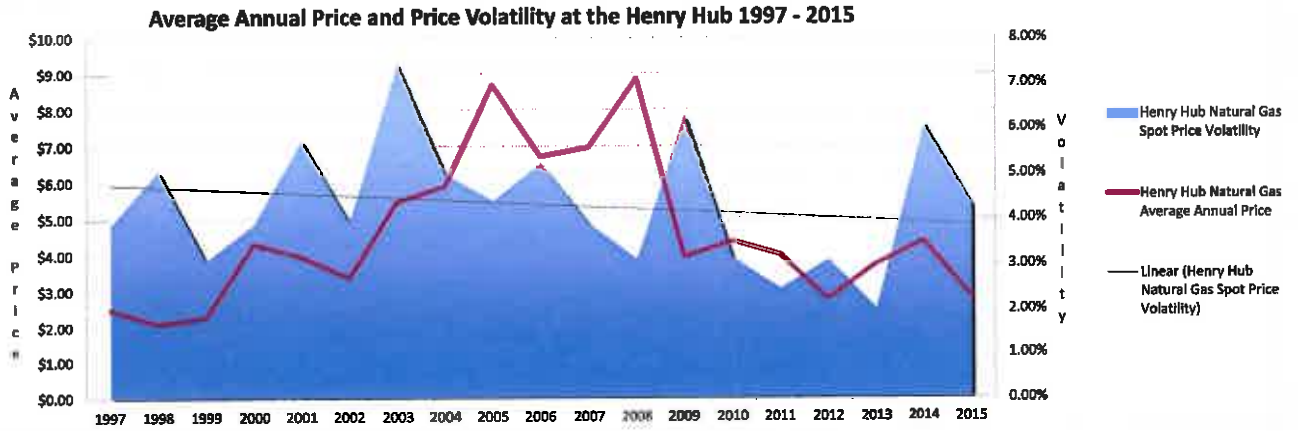
DISTRICT COURT HARRIS COUNTY, TEXAS		
City of Wharton, et al vs. Houston Lighting & Power	96-016613	Franchise fees

DISTRICT COURT TRAVIS COUNTY, TEXAS		
City of Round Rock, et al vs. Railroad Commission of Texas et al	GV 304,700	Mandamus

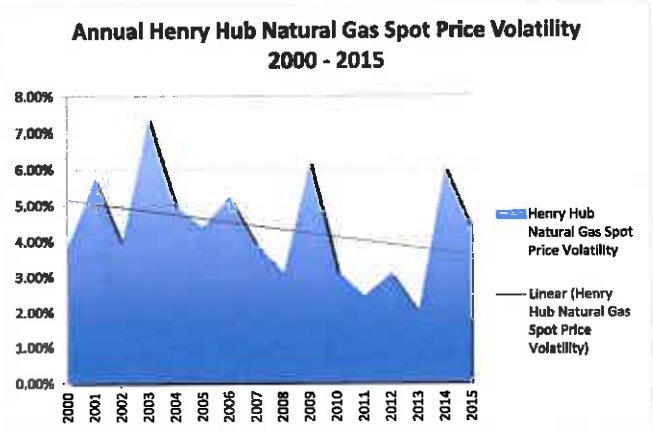
SOUTH DAYTONA, FLORIDA		
City of South Daytona v. Florida Power and Light	2008-30441-CICI	Stranded Costs

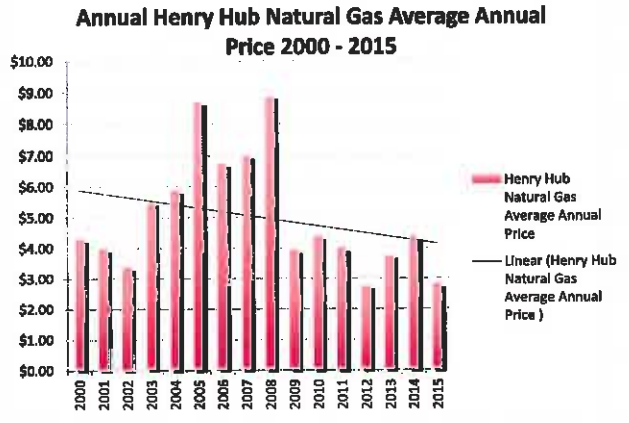
1997 - 2015 Henry Hub Natural Gas Price Historical Average Price and Price Volatility Measured Annually

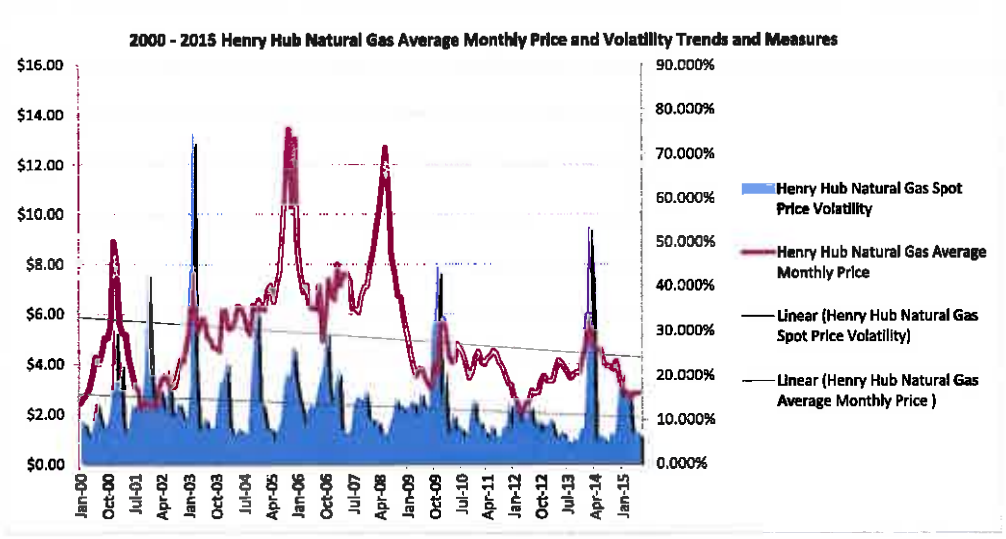
Date	Henry Hub Natural Gas Spot Price Volatility	Henry Hub Natural Gas Average Annual Price
1997	3.88%	$2.49
1998	5.08%	$2.09
1999	3.09%	$2.27
2000	3.89%	$4.31
2001	5.74%	$3.96
2002	3.94%	$3.38
2003	7.42%	$5.47
2004	4.98%	$5.89
2005	4.40%	$8.69
2006	5.23%	$6.73
2007	3.90%	$6.97
2008	3.11%	$8.86
2009	6.26%	$3.94
2010	3.14%	$4.37
2011	2.45%	$4.00
2012	3.09%	$2.75
2013	2.00%	$3.73
2014	6.08%	$4.37
2015	4.31%	$2.82
2000 to 2010	4.73%	$5.69
2011 to 2015	3.59%	$3.54
Change	-24.16%	-37.84%

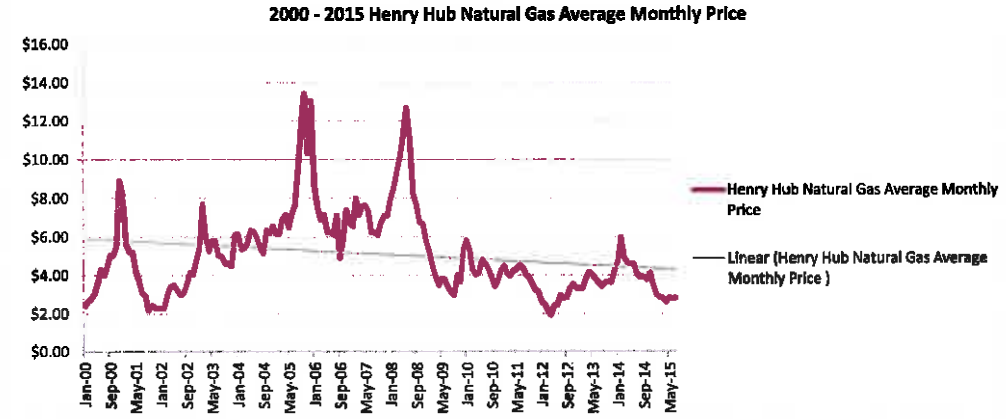


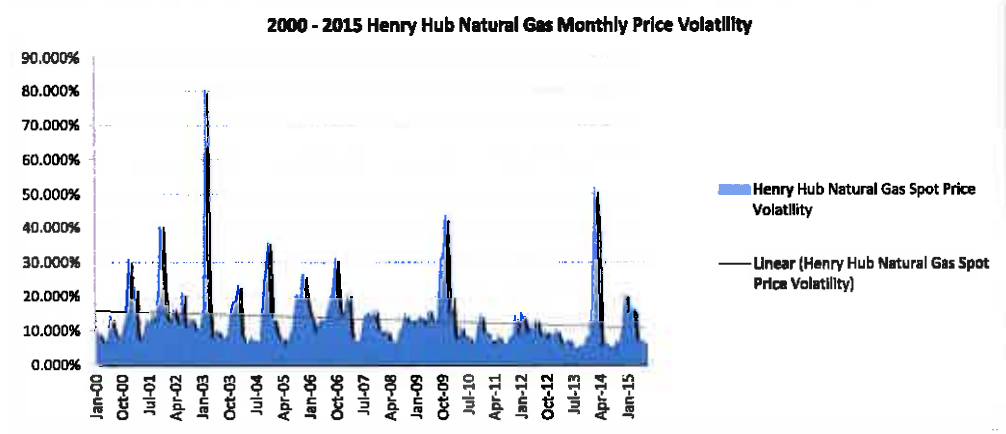
Date	Henry Hub Natural Gas Spot Price Volatility	Henry Hub Natural Gas Average Annual Price
2000	3.89%	$4.31
2001	5.74%	$3.96
2002	3.94%	$3.38
2003	7.42%	$5.47
2004	4.98%	$5.89
2005	4.40%	$8.69
2006	5.23%	$6.73
2007	3.90%	$6.97
2008	3.11%	$8.86
2009	6.26%	$3.94
2010	3.14%	$4.37
2011	2.45%	$4.00
2012	3.09%	$2.75
2013	2.00%	$3.73
2014	6.08%	$4.37
2015	4.31%	$2.82





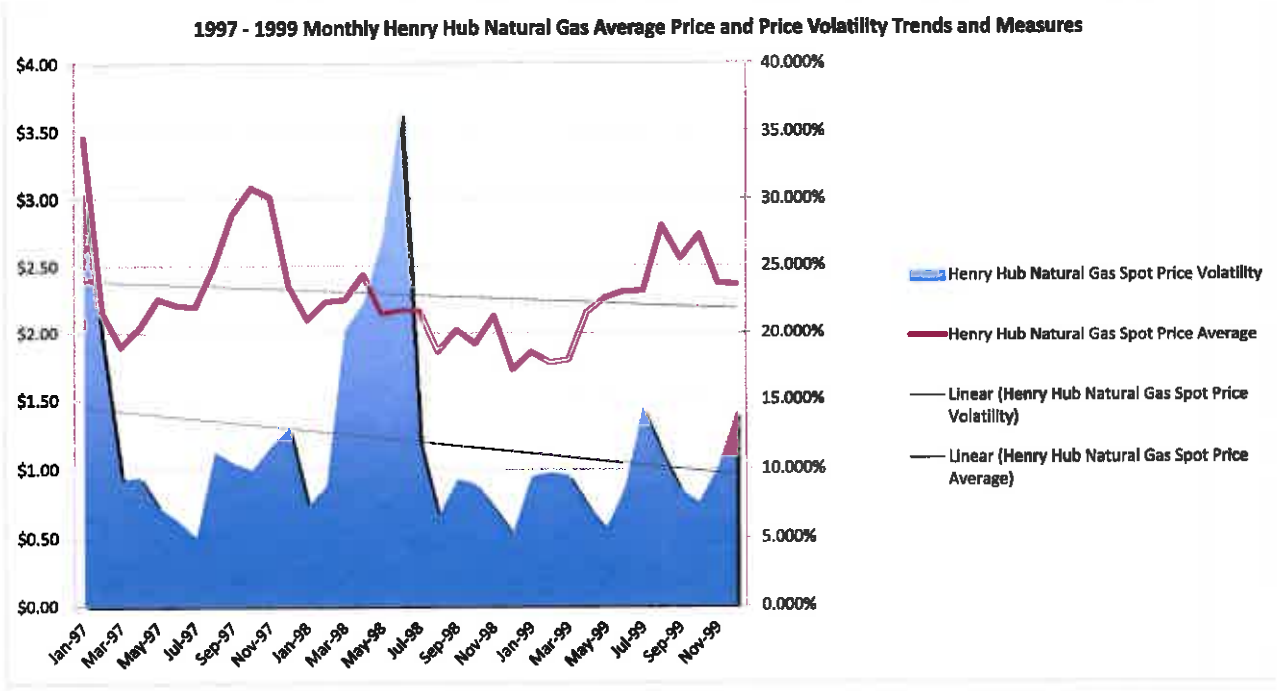




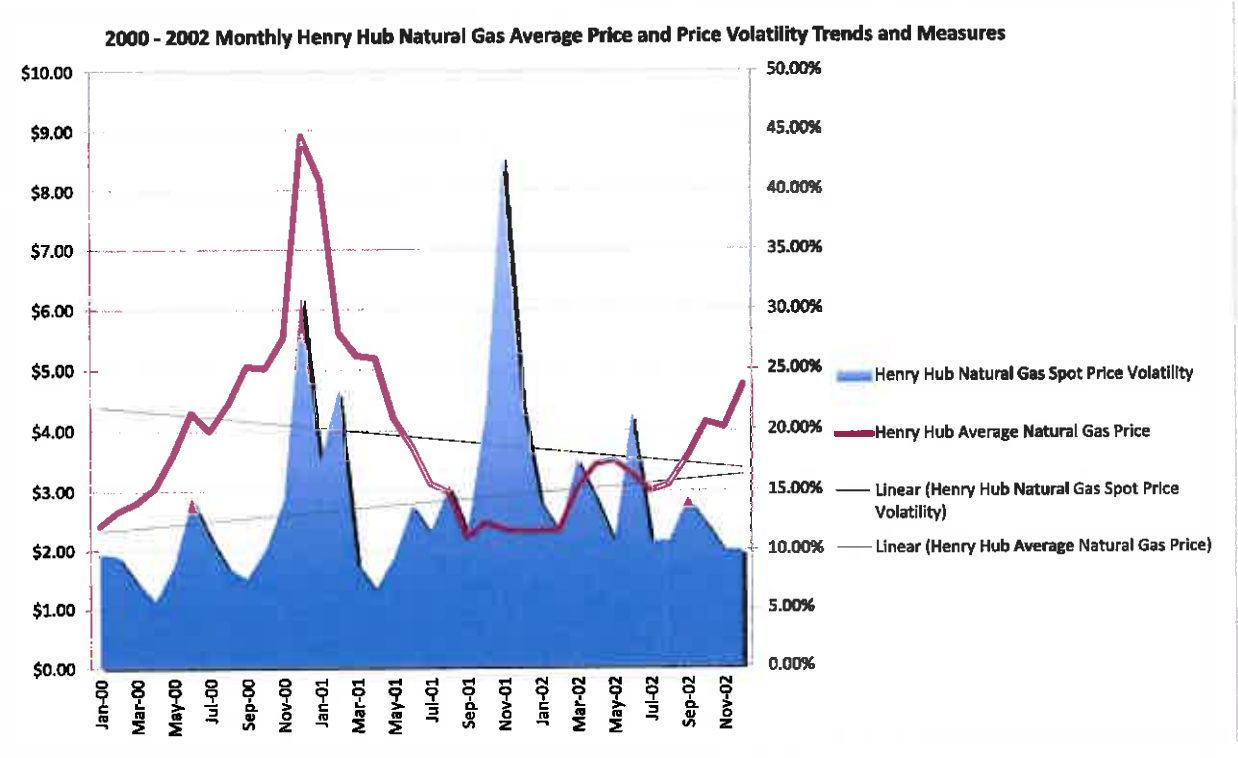


Dates	Price Volatility	Average Price
2000 - 2010	14.240%	$5.70
2011 - 2015	10.219%	$3.60
Change	-28.239%	-36.812%

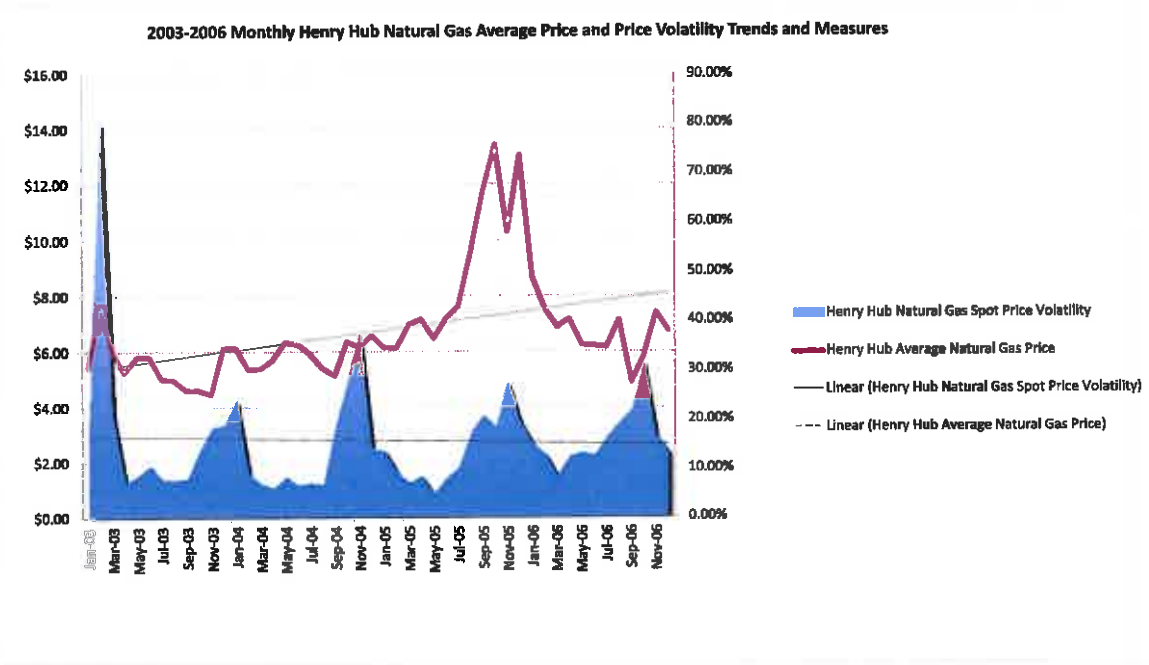
Date	Henry Hub Natural Gas Spot Price Volatility	Henry Hub Natural Gas Spot Price Average
Jan-97	30.840%	$3.45
Feb-97	18.945%	$2.15
Mar-97	9.325%	$1.89
Apr-97	9.497%	$2.03
May-97	7.344%	$2.25
Jun-97	6.377%	$2.20
Jul-97	5.125%	$2.19
Aug-97	11.322%	$2.49
Sep-97	10.533%	$2.88
Oct-97	10.002%	$3.07
Nov-97	11.655%	$3.01
Dec-97	12.948%	$2.35
Jan-98	7.397%	$2.09
Feb-98	6.876%	$2.23
Mar-98	20.299%	$2.24
Apr-98	22.317%	$2.43
May-98	27.102%	$2.14
Jun-98	36.587%	$2.17
Jul-98	11.904%	$2.17
Aug-98	6.605%	$1.85
Sep-98	9.334%	$2.02
Oct-98	8.977%	$1.91
Nov-98	7.275%	$2.12
Dec-98	5.428%	$1.72
Jan-99	9.516%	$1.85
Feb-99	9.792%	$1.77
Mar-99	9.573%	$1.79
Apr-99	7.443%	$2.15
May-99	5.720%	$2.26
Jun-99	8.622%	$2.30
Jul-99	14.394%	$2.31
Aug-99	11.208%	$2.79
Sep-99	8.554%	$2.55
Oct-99	7.639%	$2.73
Nov-99	10.116%	$2.37
Dec-99	14.229%	$2.36
Avg	12.023%	$2.29
Max	36.587%	$3.45
Min	5.125%	$1.72



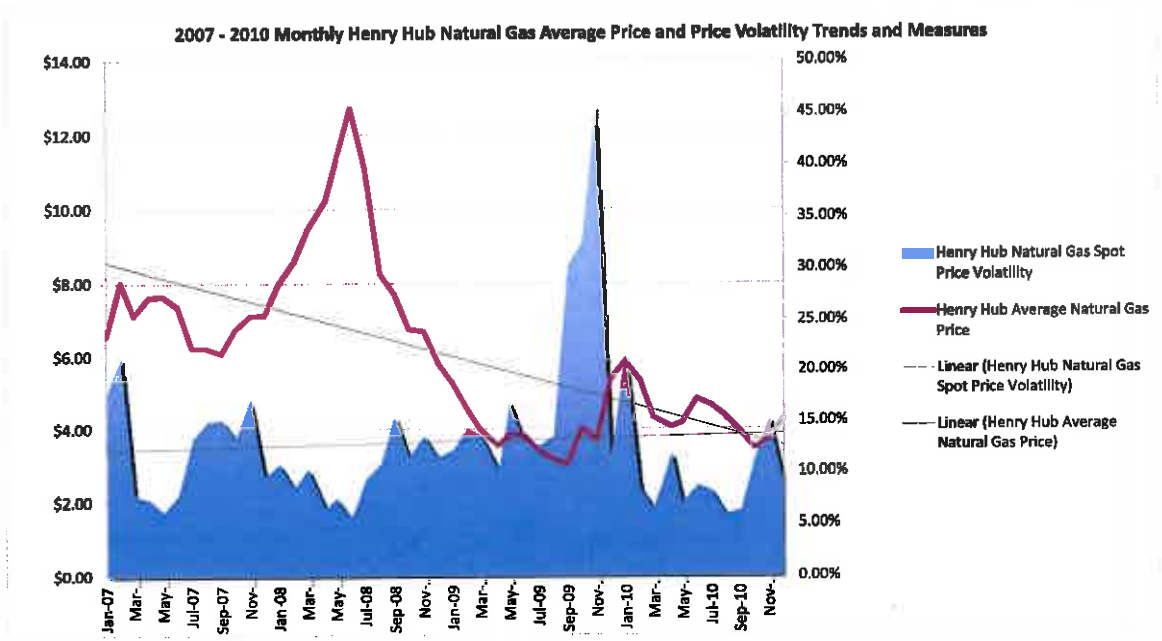
Date	Henry Hub Natural Gas Spot Price Volatility	Henry Hub Average Natural Gas Price
Jan-00	9.79%	$2.42
Feb-00	9.57%	$2.66
Mar-00	7.44%	$2.79
Apr-00	5.72%	$3.04
May-00	8.62%	$3.59
Jun-00	14.39%	$4.29
Jul-00	11.21%	$3.99
Aug-00	8.55%	$4.43
Sep-00	7.64%	$5.06
Oct-00	10.12%	$5.02
Nov-00	14.23%	$5.52
Dec-00	31.23%	$8.90
Jan-01	17.52%	$8.17
Feb-01	23.35%	$5.61
Mar-01	8.91%	$5.23
Apr-01	6.69%	$5.19
May-01	9.44%	$4.19
Jun-01	13.80%	$3.72
Jul-01	11.59%	$3.11
Aug-01	15.39%	$2.97
Sep-01	11.59%	$2.19
Oct-01	21.40%	$2.46
Nov-01	43.22%	$2.34
Dec-01	22.42%	$2.30
Jan-02	14.04%	$2.32
Feb-02	11.61%	$2.32
Mar-02	17.59%	$3.03
Apr-02	14.41%	$3.43
May-02	10.79%	$3.50
Jun-02	21.31%	$3.26
Jul-02	10.75%	$2.99
Aug-02	10.87%	$3.09
Sep-02	14.33%	$3.55
Oct-02	12.31%	$4.13
Nov-02	10.04%	$4.04
Dec-02	9.96%	$4.74
Avg	13.94%	$3.88
Max	43.22%	$8.90
Min	5.72%	$2.19



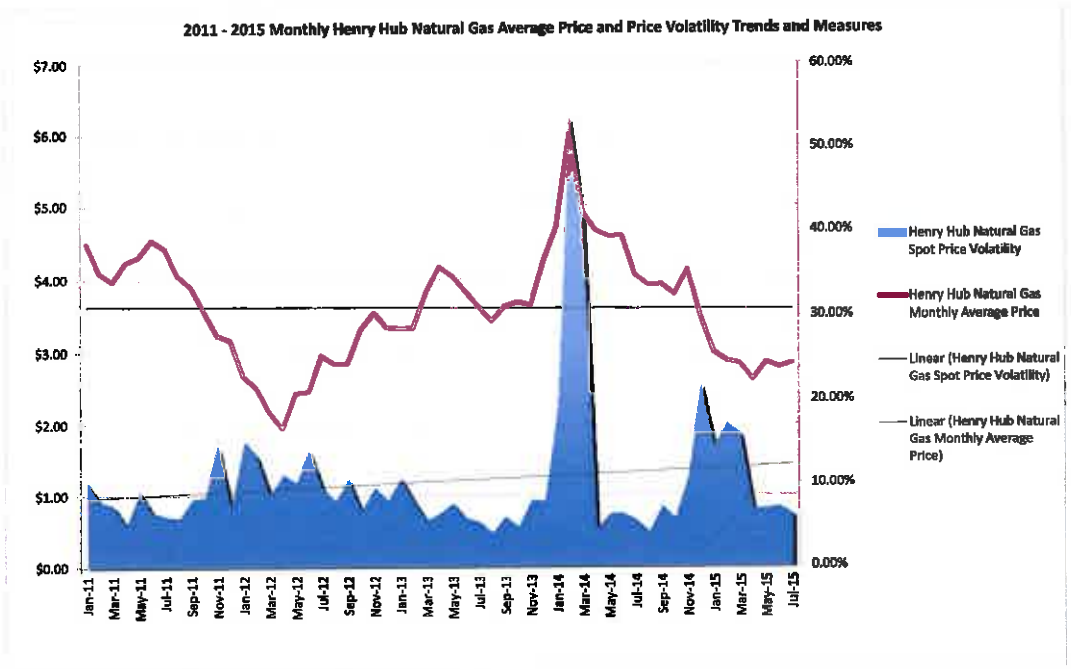
Date	Henry Hub Natural Gas Spot Price Volatility	Henry Hub Average Natural Gas Price
Jan-03	17.08%	$5.43
Feb-03	81.52%	$7.71
Mar-03	20.93%	$5.93
Apr-03	7.29%	$5.26
May-03	8.78%	$5.81
Jun-03	10.68%	$5.82
Jul-03	7.96%	$5.03
Aug-03	7.79%	$4.98
Sep-03	8.18%	$4.62
Oct-03	13.87%	$4.63
Nov-03	18.50%	$4.47
Dec-03	18.90%	$6.13
Jan-04	24.00%	$6.14
Feb-04	9.07%	$5.37
Mar-04	6.97%	$5.39
Apr-04	6.09%	$5.71
May-04	8.47%	$6.33
Jun-04	6.75%	$6.27
Jul-04	7.18%	$5.93
Aug-04	6.82%	$5.41
Sep-04	18.77%	$5.15
Oct-04	28.02%	$6.35
Nov-04	37.40%	$6.17
Dec-04	14.05%	$6.56
Jan-05	13.71%	$6.15
Feb-05	9.36%	$6.14
Mar-05	7.15%	$6.96
Apr-05	8.60%	$7.16
May-05	4.98%	$6.47
Jun-05	8.01%	$7.18
Jul-05	10.28%	$7.63
Aug-05	17.46%	$9.53
Sep-05	20.91%	$11.75
Oct-05	18.50%	$13.42
Nov-05	27.45%	$10.30
Dec-05	19.52%	$13.05
Jan-06	15.22%	$8.89
Feb-06	12.91%	$7.54
Mar-06	8.58%	$6.89
Apr-06	12.60%	$7.16
May-06	13.32%	$6.25
Jun-06	12.76%	$6.21
Jul-06	16.47%	$6.17
Aug-06	19.31%	$7.14
Sep-06	21.95%	$4.90
Oct-06	31.54%	$5.85
Nov-06	16.66%	$7.40
Dec-06	13.39%	$6.73
Avg	15.74%	$6.73
Max	81.52%	$13.42
Min	4.98%	$4.47



Date	Henry Hub Natural Gas Spot Price Volatility	Henry Hub Average Natural Gas Price
Jan-07	17.95%	$6.55
Feb-07	21.34%	$8.00
Mar-07	7.88%	$7.11
Apr-07	7.41%	$7.60
May-07	6.29%	$7.64
Jun-07	7.90%	$7.35
Jul-07	13.35%	$6.22
Aug-07	15.05%	$6.22
Sep-07	15.27%	$6.08
Oct-07	13.49%	$6.74
Nov-07	17.10%	$7.10
Dec-07	9.67%	$7.10
Jan-08	10.89%	$7.99
Feb-08	8.55%	$8.54
Mar-08	10.43%	$9.41
Apr-08	6.65%	$10.18
May-08	7.56%	$11.27
Jun-08	5.67%	$12.69
Jul-08	9.38%	$11.09
Aug-08	10.88%	$8.26
Sep-08	15.42%	$7.67
Oct-08	11.61%	$6.74
Nov-08	13.66%	$6.68
Dec-08	11.53%	$5.82
Jan-09	12.24%	$5.24
Feb-09	14.37%	$4.51
Mar-09	13.72%	$3.96
Apr-09	10.30%	$3.49
May-09	16.85%	$3.83
Jun-09	13.13%	$3.80
Jul-09	12.63%	$3.38
Aug-09	13.49%	$3.14
Sep-09	30.25%	$2.99
Oct-09	32.48%	$4.01
Nov-09	45.51%	$3.66
Dec-09	11.57%	$5.35
Jan-10	21.67%	$5.83
Feb-10	8.49%	$5.32
Mar-10	6.54%	$4.29
Apr-10	11.90%	$4.03
May-10	7.08%	$4.14
Jun-10	8.72%	$4.80
Jul-10	8.27%	$4.63
Aug-10	6.06%	$4.32
Sep-10	6.34%	$3.89
Oct-10	11.44%	$3.43
Nov-10	15.16%	$3.71
Dec-10	8.97%	$4.25
Avg	12.96%	$6.04
Max	45.51%	$12.69
Min	5.67%	$2.99

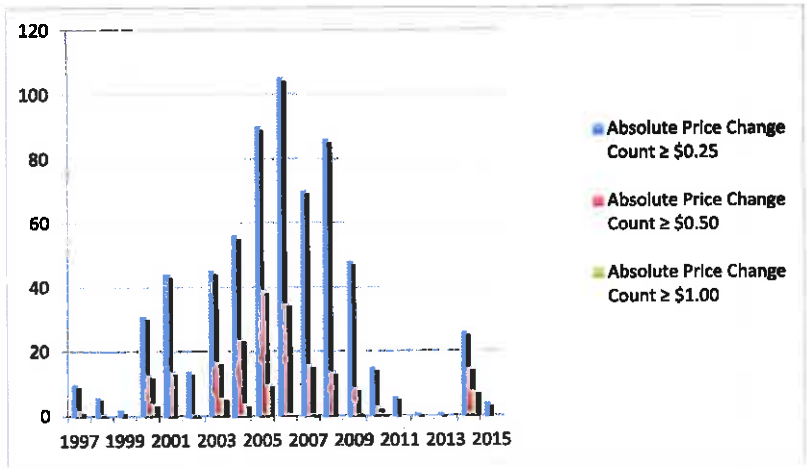


Date	Henry Hub Natural Gas Spot Price Volatility	Henry Hub Natural Gas Monthly Average Price
Jan-11	10.15%	$4.49
Feb-11	7.92%	$4.09
Mar-11	7.48%	$3.97
Apr-11	5.19%	$4.24
May-11	9.10%	$4.31
Jun-11	6.61%	$4.54
Jul-11	6.14%	$4.42
Aug-11	5.89%	$4.05
Sep-11	8.20%	$3.90
Oct-11	8.39%	$3.57
Nov-11	14.56%	$3.24
Dec-11	7.13%	$3.17
Jan-12	15.20%	$2.67
Feb-12	13.25%	$2.50
Mar-12	8.67%	$2.17
Apr-12	11.19%	$1.95
May-12	10.07%	$2.43
Jun-12	13.91%	$2.46
Jul-12	9.51%	$2.95
Aug-12	7.88%	$2.84
Sep-12	10.50%	$2.85
Oct-12	6.71%	$3.32
Nov-12	9.59%	$3.54
Dec-12	7.92%	$3.34
Jan-13	10.64%	$3.33
Feb-13	7.94%	$3.33
Mar-13	5.53%	$3.81
Apr-13	6.40%	$4.17
May-13	7.61%	$4.04
Jun-13	5.78%	$3.83
Jul-13	5.40%	$3.62
Aug-13	4.00%	$3.43
Sep-13	5.98%	$3.62
Oct-13	4.72%	$3.66
Nov-13	8.01%	$3.64
Dec-13	7.79%	$4.24
Jan-14	19.02%	$4.71
Feb-14	53.57%	$6.00
Mar-14	41.33%	$4.90
Apr-14	4.51%	$4.66
May-14	6.30%	$4.58
Jun-14	6.34%	$4.59
Jul-14	5.57%	$4.05
Aug-14	4.12%	$3.91
Sep-14	7.23%	$3.92
Oct-14	5.76%	$3.78
Nov-14	10.81%	$4.12
Dec-14	21.69%	$3.48
Jan-15	14.52%	$2.99
Feb-15	17.17%	$2.87
Mar-15	15.91%	$2.83
Apr-15	6.85%	$2.61
May-15	6.97%	$2.85
Jun-15	7.16%	$2.78
Jul-15	6.26%	$2.84
Avg	10.22%	$3.60
Max	53.57%	$6.00
Min	4.00%	$1.95



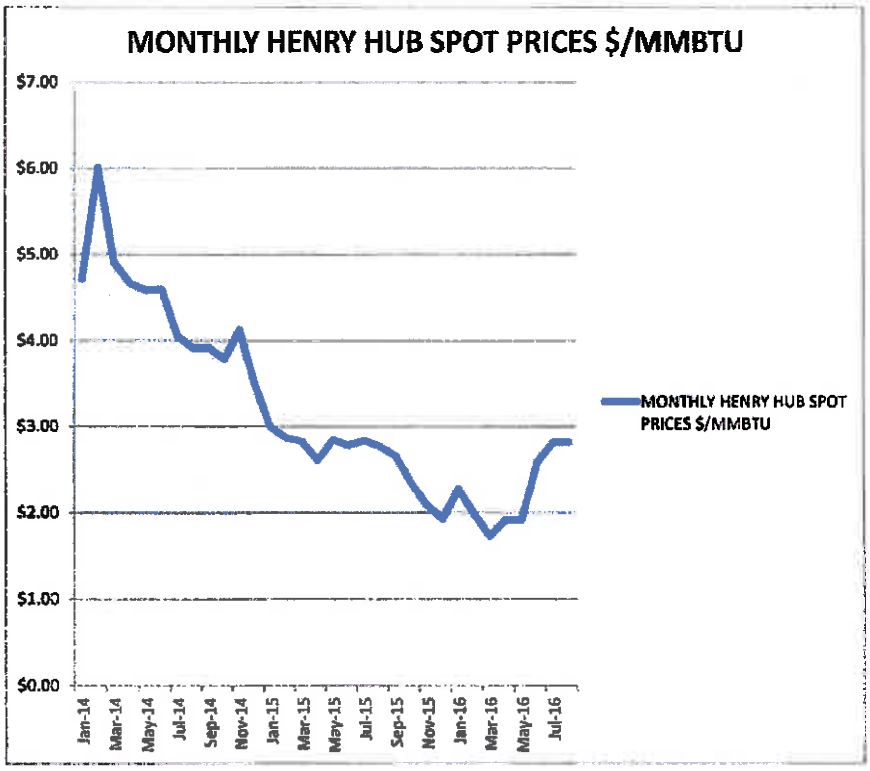
Analysis of Absolute Value of Price Changes at the Henry Hub 1997 - 2015

YEAR	Henry Hub Natural Gas Spot Price Average	Absolute Price Change Average	YEAR	Absolute Price Change Count ≥ $0.25	Absolute Price Change Count ≥ $0.50	Absolute Price Change Count ≥ $1.00
1997	$2.48	$0.07	1997	10	2	0
1998	$2.09	$0.06	1998	6	1	0
1999	$2.27	$0.05	1999	2	0	0
2000	$4.31	$0.14	2000	31	13	4
2001	$3.96	$0.14	2001	44	14	0
2002	$3.38	$0.10	2002	14	1	0
2003	$5.47	$0.26	2003	45	17	6
2004	$5.89	$0.19	2004	56	24	4
2005	$8.69	$0.29	2005	90	39	10
2006	$6.73	$0.26	2006	105	35	1
2007	$6.97	$0.20	2007	70	16	1
2008	$8.86	$0.20	2008	86	14	0
2009	$3.94	$0.16	2009	48	9	1
2010	$4.37	$0.10	2010	15	3	1
2011	$4.00	$0.07	2011	6	0	0
2012	$2.75	$0.07	2012	1	0	0
2013	$3.73	$0.06	2013	1	0	0
2014	$4.37	$0.15	2014	26	15	8
2015	$2.82	$0.06	2015	4	0	0



MONTHLY SPOT HENRY HUB NATURAL GAS PRICES JANUARY 2014 - AUGUST 2016 ($/MMBTU)

LINE NO.	DATE	MONTHLY HENRY HUB SPOT PRICES $/MMBTU
1	Jan-14	$4.71
2	Feb-14	$6.00
3	Mar-14	$4.90
4	Apr-14	$4.66
5	May-14	$4.58
6	Jun-14	$4.59
7	Jul-14	$4.05
8	Aug-14	$3.91
9	Sep-14	$3.92
10	Oct-14	$3.78
11	Nov-14	$4.12
12	Dec-14	$3.48
13	Jan-15	$2.99
14	Feb-15	$2.87
15	Mar-15	$2.83
16	Apr-15	$2.61
17	May-15	$2.85
18	Jun-15	$2.78
19	Jul-15	$2.84
20	Aug-15	$2.77
21	Sep-15	$2.66
22	Oct-15	$2.34
23	Nov-15	$2.09
24	Dec-15	$1.93
25	Jan-16	$2.28
26	Feb-16	$1.99
27	Mar-16	$1.73
28	Apr-16	$1.92
29	May-16	$1.92
30	Jun-16	$2.59
31	Jul-16	$2.82
32	Aug-16	$2.82
33		
34	Avg 2014	$4.39
35	Avg 2015	$2.63
36	Avg 2016	$2.26
37	Avg Last 12 Mos	$2.26



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 62
PARTY: OFFICE OF PUBLIC COUNSEL – (DIRECT)
DESCRIPTION: Daniel J. Lawton DJL-3

FLORIDA UTILITY HEDGING GAINS & LOSSES SUMMARY (2002 TO 2016)*

Totals Gains/Losses By Year Year	Duke	FPL	Gulf	TECO	TOTALS FOR THE FOUR IOUs 2002-2016
2002	$ (2,098,791)	$ 14,520,306	$ 238,750	$ (203,500)	$ 12,456,765
2003	$ 19,772,126	$ (15,939,810)	$ 4,862,077	$ (2,758,028)	$ 5,936,365
2004	$ 51,068,145	$ 191,564,536	$ 6,652,157	$ 8,413,170	$ 257,698,008
2005	$ 121,672,401	$ 519,388,788	$ 22,571,976	$ 53,231,770	$ 716,864,935
2006	$ 62,066,818	$ (416,637,197)	$ (18,714,562)	$ (54,482,120)	$ (427,767,061)
2007	$ (34,399,955)	$ (799,268,428)	$ (9,197,433)	$ (59,691,520)	$ (902,557,336)
2008	$ 116,935,706	$ 100,709,736	$ (1,737,726)	$ 18,147,375	$ 234,055,091
2009	$ (556,149,474)	$ (1,660,695,829)	$ (51,232,251)	$ (193,185,985)	$ (2,461,263,539)
2010	$ (285,863,553)	$ (509,147,046)	$ (19,667,161)	$ (67,840,710)	$ (882,518,470)
2011	$ (240,882,264)	$ (404,239,340)	$ (15,444,523)	$ (33,889,480)	$ (694,455,607)
2012	$ (351,321,610)	$ (671,819,795)	$ (32,865,554)	$ (61,518,120)	$ (1,117,525,079)
2013	$ (140,907,108)	$ 18,253,045	$ (14,654,866)	$ (3,256,370)	$ (140,565,299)
2014	$ (27,741,075)	$ 116,639,265	$ 1,910,889	$ 15,615,785	$ 106,424,864
2015	$ (225,543,645)	$ (504,393,229)	$ (50,572,362)	$ (39,842,325)	$ (820,351,561)
2016 (Jan. 1-July 31 Actuals)	$ (114,900,000)	$ (190,763,980)	$ (37,505,696)	$ (17,877,735)	$ (361,047,411)
Total Gains/(Losses) Actuals	**$ (1,608,292,279)**	**$ (4,211,828,978)**	**$ (215,356,285)**	**$ (439,137,793)**	**$ (6,474,615,335)**
2016 (Aug. 1-Dec. 31 Projected)	$ (30,600,000)	$ (34,625,394)	$ (17,063,422)	$ (583,030)	$ (82,871,846)
Total Gains/(Losses) w/ 2016 Projections	**$ (1,638,892,279)**	**$ (4,246,454,372)**	**$ (232,419,707)**	**$ (439,720,823)**	**$ (6,557,487,181)**

*As of September 7, 2016, based on IOUs' responses to OPC discovery.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 63
PARTY: OFFICE OF PUBLIC COUNSEL – (DIRECT)
DESCRIPTION: Daniel J. Lawton DJL-4

Docket No. 160001-EI
Exhibit DJL-4
Hedging Gains & Losses Summary (2002-2016)
Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 64
PARTY: OFFICE OF PUBLIC COUNSEL – (DIRECT)
DESCRIPTION: Daniel J. Lawton DJL-5

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 160021-EI
PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY.
_____/

DOCKET NO. 160061-EI
PETITION FOR APPROVAL OF 2016-2018 STORM HARDENING PLAN BY FLORIDA POWER & LIGHT COMPANY.
_____/

DOCKET NO. 160062-EI
2016 DEPRECIATION AND DISMANTLEMENT STUDY BY FLORIDA POWER & LIGHT COMPANY.
_____/

DOCKET NO. 160088-EI
PETITION FOR LIMITED PROCEEDING TO MODIFY AND CONTINUE INCENTIVE MECHANISM, BY FLORIDA POWER & LIGHT COMPANY.
_____/

TELEPHONIC DEPOSITION OF:	MORAY DEWHURST
TAKEN AT THE INSTANCE OF:	The Staff of the Florida Public Service Commission
PLACE:	Room 382D Gerald L. Gunter Building 2540 Shumard Oak Boulevard Tallahassee, Florida
TIME:	Commenced at 2:00 p.m. Concluded at 6:06 p.m.
DATE:	Thursday, August 4, 2016
REPORTED BY:	ANDREA KOMARIDIS Court Reporter and Notary Public in and for the State of Florida at Large

Does FPL need a strong balance sheet to support its natural gas hedging?

A It depends. It depends, obviously, on the extent of the hedging program, but certainly that is an application of financial strength that, at various times, has benefited from the support of the balance sheet.

The balance sheet is a general resource that has, you know, multiple ways in which it can be applied. But certainly, the fuel-hedging program is one of them, but -- as is the basic fuel-purchasing program.

Q Okay. How would reducing FPL's equity ratio from 59.6 percent of investor capital to 50 percent affect FPL's ability to hedge natural gas?

A It's hard to put numbers around that. I would say it would dramatically diminish our ability to support either the hedging program or a variety of other needs.

A move from 59.6 to 50 percent would have major negative consequences in a variety of areas, but one of them would be that we would no longer have -- well, over time, we would no longer have access to the same level of liquidity and, therefore, we wouldn't be able to respond to the kinds of short-term, unexpected events that we do now.

Q And in terms of natural gas, an unexpected event might be a supply interruption and increased natural gas price in the short-term?

A Yes, those would be two major ones. To the extent that, if we are unhedged, hypothetically, and we have a significant increase in gas prices, then, obviously, we're going to have an under-recovery through the fuel clause.

We have to have the financial flexibility to be able to go out and buy the fuel, convince the suppliers that we're going to pay for it. If we don't have the balance sheet, we would not be able to do that. So, that's a fuel- -- fuel-price element. And there is certainly a fuel-supply-interruption element.

Q And I want to make sure I understand what you just told me. My understanding is that FP&L is allowed to recover its fuel costs through the fuel clause, and that those costs are trued up on an annual basis; is that right?

A That's correct; although, the true-up may be from an accrual perspective on an annual basis. The recovery of the cash may well -- and certainly in the past, has extended over more than one year.

In either case, however, we have to have the cash to be able to go and buy the fuel for the benefit

of our customers. And so, the liquidity need comes in there.

So, there's a distinction between ultimate recovery of prudently-incurred costs and the need to be able to fund what can be pretty large swings in cash flow. It's swings in cash flow that require the balance sheet and liquidity support.

Q And so, basically, you're talking about being able to bridge the time in which there is a regulatory lag between having to spend the money and being able to recover it.

A Yes, but I think it's more than that because it's -- had it been able to do that and then still be in a position to continue to do all the other aspects of running the business and delivering value to customers without that changing.

So, just by way of example, in my past experience in the consulting business, I've seen plenty of examples of companies that start to get squeezed on liquidity. And one of the consequences in response to that is that they are forced to make changes on the operational side of the business which are detrimental. We want to avoid that.

Q Got it.

If the Commission were to reduce FP&L's equity

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 65
PARTY: OFFICE OF PUBLIC COUNSEL – (DIRECT)
DESCRIPTION: Daniel J. Lawton DJL-6

Docket No. 160001-EI
Exhibit DJL-6
FPL Witness Yupp's 2015 Analysis of
Hedging Volatility Reduction Benefits
Page 1 of 1

Florida Power & Light Company
Docket No. 150001-EI
Exhibit GJY-7, Page 1 of 1
Corrected Responses: OPC's 12th Set of Interrogatories Nos. 127 and 128

Corrected Response - Interrogatory Nos. 127 and 128 - OPC's 12th Set of Interrogatories

Final True-Up Filing Data Year	Jurisdictional Total Fuel Costs & Net Power Transactions	Jurisdictional Fuel Revenues Applicable to Period	Cumulative Monthly True-up Amount - Over/(Under) Recovery	Percent Variance	Hedging Savings/(Costs)	Revised Jurisdictional Total Fuel Costs & Net Power Transactions	Jurisdictional Fuel Revenues Applicable to Period	Cumulative Monthly True-up Amount - Over/(Under) Recovery	Percent Variance
2002	$2,459,001,016	$2,377,739,316	($81,261,700)	-3.42%	$46,994,088	$2,505,995,103	$2,377,739,316	($128,255,786)	-5.39%
2003	$3,444,197,949	$3,144,836,744	($299,361,205)	-9.52%	$15,701,704	$3,459,899,653	$3,144,836,744	($315,062,909)	-10.02%
2004	$3,484,396,810	$3,296,934,142	($187,462,668)	-5.69%	$251,922,139	$3,736,318,949	$3,296,934,142	($439,384,807)	-13.33%
2005	$4,906,808,719	$3,879,452,165	($1,027,356,554)	-26.48%	$625,001,024	$5,531,809,743	$3,879,452,165	($1,652,357,578)	-42.60%
2006	$5,427,041,074	$5,620,725,235	$193,684,161	3.45%	($468,638,337)	$4,958,402,737	$5,620,725,235	$662,322,498	11.78%
2007	$6,016,453,717	$5,874,686,707	($141,767,010)	-2.41%	($855,797,821)	$5,160,655,896	$5,874,686,707	$714,030,811	12.15%
2008	$6,084,621,247	$5,839,073,540	($245,547,707)	-4.21%	$368,264,441	$6,452,885,688	$5,839,073,540	($613,812,148)	-10.51%
2009	$5,253,110,989	$5,688,508,594	$435,397,605	7.65%	($1,723,597,065)	$3,529,513,924	$5,688,508,594	$2,158,994,670	37.95%
2010	$4,576,587,132	$4,323,584,596	($253,002,536)	-5.85%	($500,229,888)	$4,076,357,244	$4,323,584,596	$247,227,352	5.72%
2011	$4,136,187,692	$4,079,099,228	($57,088,464)	-1.40%	($387,658,446)	$3,748,529,246	$4,079,099,228	$330,569,982	8.10%
2012	$3,571,615,003	$3,666,288,610	$94,673,607	2.58%	($669,142,129)	$2,902,472,874	$3,666,288,610	$763,815,736	20.83%
2013	$3,236,315,354	$3,093,026,968	($143,288,386)	-4.63%	$17,542,395	$3,253,857,749	$3,093,026,968	($160,830,781)	-5.20%
2014	$3,504,345,523	$3,248,028,140	($256,317,383)	-7.89%	$116,639,265	$3,620,984,788	$3,248,028,140	($372,956,648)	-11.48%

Note: This corrected table answers both Interrogatories

Attachment A
Page 1 of 3

Entergy Texas, Inc.
Proposed Fuel Factor
Sep-16

Sep-16

Line No.			
1	Actual FF Expense (8/15 through 7/16)	$	466,261,533
2	Less: Coal and Nuclear FF Expense	$	46,454,707
3	Adjusted FF Expense w/o Coal and Nuclear	$	419,806,826
4	Multiplied by: Projected Market Factor		137.6%
5	September 2015 Fuel Factor Expense	$	577,654,193
6	Add: Coal and Nuclear FF Expense	$	46,454,707
7	September 2015 Fuel Factor Expense	$	624,108,900
8	Divided by: Actual FF Sales (8/15 through 7/16)		17,937,371,449
9	Average Fuel Factor Rate ($/MWH)	$	34.7838

Projected Market Factor:

Simple Average (Henry Hub Price 9/16 through 8/17)	$	3.06
Simple Average (Henry Hub Price 8/15 through 7/16)	$	2.22
		137.6%

(A) Voltage Level	(B) Loss Multiplier	(C) Line 9*Column B Voltage Level Factor
Secondary	1.026844	35.7278
Primary	1.000116	34.7978
69kV and 138 kV	0.962408	33.4858
230kV	0.947964	32.9832

Note: The loss multipliers are those developed by a line loss study for the annual period ended December 31, 2014, consistent with Docket No. 40654

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 66
PARTY: OFFICE OF PUBLIC COUNSEL – (DIRECT)
DESCRIPTION: Daniel J. Lawton DJL-7

Entergy Texas, Inc.
Fixed Fuel Factor Sales at Meter
August 2015 - July 2016

EGSI-TX
FFF Sales at Meter

Month	kWh Sales	Annual FF Sales
Aug-15	1,822,561,064	
Sep-15	1,719,372,815	
Oct-15	1,499,496,170	
Nov-15	1,376,127,761	
Dec-15	1,313,225,358	
Jan-16	1,519,458,684	
Feb-16	1,370,860,771	
Mar-16	1,276,438,570	
Apr-16	1,287,373,222	
May-16	1,399,616,127	
Jun-16	1,597,370,973	
Jul-16	1,753,469,964	17,937,371,449

Attachment B
Page 1 of 2

Entergy Gulf States, Inc.
Henry Hub Settlement Prices
Per Wall Street Journal

Publish Date	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Average
1-Aug	2.676	2.817	3.076	3.320	3.436	3.418	3.360	3.070	3.038	3.068	3.086	3.104	3.148
2-Aug	2.771	2.818	2.980	3.239	3.357	3.344	3.295	3.030	3.002	3.034	3.063	3.073	3.084
3-Aug	2.733	2.783	2.943	3.199	3.315	3.304	3.259	3.020	2.998	3.033	3.064	3.074	3.080
4-Aug	2.839	2.861	3.034	3.276	3.392	3.378	3.328	3.072	3.043	3.074	3.103	3.111	3.128
5-Aug	2.834	2.877	3.022	3.267	3.385	3.372	3.324	3.068	3.040	3.072	3.102	3.111	3.123
6-Aug	2.772	2.809	2.985	3.217	3.338	3.328	3.283	3.038	3.011	3.045	3.078	3.086	3.091
9-Aug	2.748	2.779	2.943	3.191	3.317	3.309	3.266	3.029	3.003	3.035	3.065	3.075	3.083
10-Aug	2.615	2.659	2.844	3.098	3.232	3.226	3.186	2.984	2.941	2.975	3.008	3.016	2.980
11-Aug	2.561	2.616	2.801	3.059	3.197	3.192	3.154	2.940	2.918	2.952	2.983	2.993	2.947
12-Aug	2.551	2.607	2.782	3.051	3.190	3.185	3.147	2.931	2.909	2.945	2.976	2.985	2.939
Average	2.730	2.775	2.949	3.192	3.316	3.305	3.260	3.016	2.990	3.029	3.063	3.073	3.055

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, 2016

Docket No. 160001-EI
Audit Control No. 16-068-2-1
September 7, 2016

Simon O. Ojada
Audit Manager

Linda Hill
Reviewer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 67
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 February 26, 2016. We applied these procedures to the schedules prepared by Duke Energy Florida, LLC in support of its filing for hedging activities in Docket No. 160001-EI for the twelve months ended July 31, 2016.

This audit was performed following General Standards and Fieldwork Standards found in the AICPA Statements on Standards for Attestation Engagements. 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-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, and as clarified by Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, and Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI.

Procedures: We obtained DEF's supporting detail of the hedging settlements for the 12 months ended July 31, 2016. The support documentation was reconciled to the general ledger transaction detail. We verified that the hedging settlements were in compliance with the Risk Management Plan and that the accounting treatment for hedging transactions and transaction costs is 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 DEF implemented are in compliance with Commission Order Nos. PSC-02-1484-FOF-EI, PSC-08-0316-PAA-EI, and PSC-08-0667-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, 2015, through July 31, 2016, to its Hedging Summary by Commodity Reports for 2015 and 2016. 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 August 2015 through July 2016 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. We obtained DEF's analysis of the monthly percent of fuel hedged in relation to fuel burned for the 12 months ended July 31, 2016, and compared them with the Utility's Risk Management Plan. 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 ending December 31, 2015, for the Regulated Fuels Inventory Management Process and the Regulated Trading Cycle. There was no external audit 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
Miami District Office

Auditor's Report

Florida Power & Light Company
Hedging Activities

Twelve Months Ended July 31, 2016

Docket No. 160001-EI
Audit Control No. 16-068-4-1
August 19, 2016

Marisa N. Glover
Audit Manager

Lynn M. Deamer
Reviewer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 68
PARTY: STAFF – (DIRECT)
DESCRIPTION: Iliana H. Piedra(Marissa N. Glover) MNG-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 set forth by the Division of Accounting and Finance in its audit service request dated February 26, 2016. We have applied these procedures to the attached schedules prepared by Florida Power & Light Company in support of its filing for hedging activities in Docket No. 160001-EI.

This audit was performed following General Standards and Fieldwork Standards found in the AICPA Statements on Standards for Attestation Engagements. The report is intended only for internal Commission use.

Objectives and Procedures

Definitions

FPL or Utility refers to Florida Power & Light Company.

Accounting Treatment

Objectives: The objective was to determine whether the accounting treatment for futures, opinions, and swap contracts between FPL and its counterparties is consistent with Commission Order No. PSC-02-1484-FOF-EI, issued October 30, 2002 in Docket No. 011605-EI, and as clarified by Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, and Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI.

Procedures: We obtained FPL's supporting detail of the hedging settlements for the twelve months ended July 31, 2016. We verified that the hedging settlements were in compliance with the Risk Management Plan and determined that the accounting treatment for hedging transactions and transaction costs is consistent with Commission orders relating to hedging activities. No exceptions were noted.

Gains and Losses

Objectives: The objective was to determine whether gains and losses associated with each financial hedging instrument that FPL implemented are in compliance with Commission Order Nos. PSC-02-1484-FOF-EI, PSC-08-0316-PAA-EI, and PSC-08-0667-PAA-EI, relating to hedging activities.

Procedures: We traced the monthly balances of hedging transactions from FPL's April 6, 2016 and August 18, 2016 filings in this docket for the period August 1, 2015 to July 31, 2016 to FPL's Derivative Settlement Report. We selected a sample of hedging transactions from various counterparties from November 2015 and March 2016 for natural gas and traced them from the Derivative Settlement Report to the invoices, purchase statements, confirmation notices and deal tickets. We compared a sample of the purchase prices to the Gas Daily- NYMEX Henry Hub gas futures contract rates. We traced the floating price to the Settlement Price worksheet and to the Gas Daily – NYMEX Henry Hub gas futures contract rates provided by the Utility. We recalculated the gains and losses. We compared the recalculated gains and losses with FPL's journal entries for realized gains and losses. FPL does not have any tolling agreements where natural gas is provided to generators under purchased power agreements. Physical hedging transactions were reviewed for the months of November 2015 and March 2016. The losses were recalculated. No exceptions were noted.

Hedged Volume and Limits

Objectives: 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 FPL's analysis of the monthly percent of fuel hedged in relation to fuel burned for the twelve months ended July 31, 2016, and compared them with the Utility's Risk Management Plan. The hedged targets for natural gas were traced to the Planned Position Strategy Schedule. The fuel burn forecast was traced to the Fuel Burn Summary. No exceptions were noted.

Separation of Duties

Objectives: The objective was to review FPL's procedures for separating duties related to hedging activities for front office, middle office, and back office and to review internal and external auditor's work papers.

Procedures: We reviewed the Utility's procedures for separating duties related to hedging activities. We verified the separation of duties during out testing of transactions by agreeing the names of various employees from deal tickets and confirmations to FPL's procedures. According to the Utility there has not been any internal or external audits related to the hedging a ctivities. 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, 2016

Docket No. 160001-EI
Audit Control No. 16-068-1-1
August 31, 2016

Donna D. Brown
Audit Staff

Marisa N. Glover
Reviewer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 69
PARTY: STAFF – (DIRECT)
DESCRIPTION: George Simmons (Donna D. Brown) DDB-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 3, 2016. 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. 160001-EI.

This audit was performed following General Standards and Fieldwork Standards found in the AICPA Statements on Standards for Attestation Engagements. 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-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, and as clarified by Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, and Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI.

Procedures: We obtained GPC's supporting detail of the hedging settlements for the twelve months ended July 31, 2016. 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 account treatment for hedging transactions and transactions costs is consistent with Commission orders relating to hedging activities. 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-02-1484-FOF-EI, PSC-08-0316-PAA-EI, and PSC-08-0667-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, 2015 to July 31, 2016. We reviewed existing tolling arrangements 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 month ended July 31, 2016, and compared them with the Utility's 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 reviewed internal audit reports from August 1, 2015 to July 31, 2016 and noted that one pertained to the review of the fuel hedging program and was issued July 12, 2016 with no reportable findings. No further work was done.

Audit Findings

None

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, 2016

Docket No. 160001-EI
Audit Control No. 16-068-2-2
September 12, 2016

Intesar Terkawi
Audit Manager

Linda Hill
Reviewer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 70
PARTY: STAFF – (DIRECT)
DESCRIPTION: Intesar Terkerkawi IT-1

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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 February 26, 2016. We applied these procedures to the schedules prepared by Tampa Electric Company in support of its filing for hedging activities in Docket No. 160001-EI for the twelve months ended July 31, 2016.

This audit was performed following General Standards and Fieldwork Standards found in the AICPA Statements on Standards for Attestation Engagements. 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-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, and as clarified by Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, and Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI.

Procedures: We obtained TECO's supporting detail of the hedging settlements for the 12 months ended July 31, 2016. The support documentation was traced to the general ledger transaction detail. We verified that the hedging settlements were in compliance with the Risk Management Plan and 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-02-1484-FOF-EI, PSC-08-0316-PAA-EI, and PSC-08-0667-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, 2015, to July 31, 2016. We selected all gas hedging transactions from September and October 2015 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 the 12 months ended July 31, 2016, and compared them with the Utility's Risk Management Plan. There were variances for 11 of the 12 months between the percentages of actual and projected natural gas burned that were hedged. The variances in the months of September and October 2015, and January, February, March, April, June, and July 2016 were a result of inaccurate forecasting. The variances in the months of August, November and December 2015 were a result of increased load and reduced coal-fired generation.

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. We reviewed the notes of the internal audit performed on the separation of duties related to hedging activities. There was no external audit that specifically performed on the separation of duties related to hedging activities. No exceptions were noted.

Audit Findings

None

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 71
PARTY: STAFF – (DIRECT)
DESCRIPTION: Michael A. Gettings MAG-1

Curriculum Vitae

Michael A. Gettings
Senior Partner

Industry Experience: 40 years

Qualifications and Experience:

Mr. Gettings is the Senior Partner at RiskCentrix, LLC. In reverse chronological order his career has included:

- 20 years as executive consultant in the energy field, including commodity risk management and risk-cognizant strategic planning with an emphasis on utilities' needs (RiskCentrix and Pace Global)
- 10 years as founder and president of a natural gas marketing and trading company (O&R Energy)
- 10 years in utility ratemaking and financial/economic analysis (Orange and Rockland Utilities)

As a consultant Mr. Gettings has participated as an ex officio member on the executive risk management committees of numerous utilities, including some of the nation's largest public power companies. He established numerous utility and industrial risk mitigation programs and added clarity and discipline to many more. He founded the Risk and Utilities Division of Pace Global (since acquired by Siemens) consisting of risk consulting and advisory services, risk systems integration, and utility strategy development. Mr. Gettings has been an advisor to the executive suite of numerous utilities, Fortune 500 industrials, and wholesale trading companies.

Earlier in his career, following the deregulation of gas markets, Mr. Gettings started O&R Energy, a gas trading and marketing firm, and guided that company through its extraordinary growth as third-party gas supply emerged as a major factor in the energy industry. Perhaps more important to today's environment, following the advent of the NYMEX futures exchange in the early 1990's, Mr. Gettings established a hedging program at O&R Energy which positioned him as an early adopter and ultimately as an expert in the field of risk mitigation.

Finally, his experience in the fields of trading and risk mitigation is supplemented by an early grounding in utility ratemaking, regulatory affairs, and financial analysis for a combination electric and gas utility that operated in three states (NY. NJ, PA).

Examples of Mr. Gettings' relevant experience include:

- Consulted on numerous strategic issues, particularly in the utility industry, including areas related to risk mitigation, resource planning, rating agency issues, acquisitions, ratemaking and regulatory implications, etc.
- Directed development of a rigorous and customizable structure of hedging decision protocols for energy risk mitigation and links to related corporate-level strategic objectives. These protocols consist of programmatic, defensive, and discretionary hedging rules which provide a covenant between executives and hedging managers, thus enabling responsive but well-conditioned risk mitigation tied to P&L, cost-of-service, or other objectives.

- Developed an Enterprise-wide Risk Management ("ERM") approach that linked parametric and contingent-event risk assessments into a financial management process. Related ERM perspectives into development of rating agency storyboards.
- Initiated the development of various trading and risk management tools including proprietary market timing models and models to simulate performance against historical or postulated price environments.
- Initiated the development of web-based information systems for the routine measurement of risk, and tied these systems to business perspectives relating market risks to overarching corporate objectives such as earnings, competitiveness, etc. In addition, developed customized application of these tools to various client cultures and risk appetites.
- Founded and presided over natural gas marketing and trading company. As president of O&R Energy, was responsible for strategy and oversight related to commercial sales and trading activity of approximately $1 billion annually. Also initiated and negotiated the sale of an interest to a major oil company.
- For utilities and industrial concerns, drafted and saw through to board of directors' ratification, risk policy and procedure documentation.

Publications & Testimony

Quoted in Wall Street Journal, U.S. Utilities' Natural-Gas Hedges Turn Sour, Rebecca Smith, April 2016

Natural Gas Utility Hedging Practices and Regulatory Oversight, a white paper prepared for The Washington Utilities and Transportation Commission, July 2015

NARUC Hedging Panel, February 2015 Presentation / Utilities Deserve Clarity as to Prudence Standards

Prudence Standards for Utility Hedging, NARUC Winter Committee Meetings, February 2015 White Paper

By Executive Decision, Public Utilities Fortnightly, October 2005
- Henry Fayne, Michael Gettings, Wes Mitchell, and Gary Vicinus

Provided expert witness testimony in legislative, regulatory, and civil proceedings in NY, NJ, PA, DE, WA, etc. Topics have included:

- In the risk domain: strategy formulation, economics and risk of long term commitments, policies and procedures, trading incentives, evaluation of hedge structures, quantification of damages, etc.
- In the non-risk domain: ratemaking support, capital project economics, off-shore wind power economics, marginal and embedded cost assessments, load research and forecasting, etc.

Boards:

Mr. Gettings serves or has served on the boards of directors of RiskCentrix, Pace Global, O&R Energy, Atlantic Morris Broadcasting, and related holding companies. He serves or has served as ex officio member/advisor to the Executive Risk Management Committees of Long Island Power Authority, New York Power Authority, Duquesne Light Company, and numerous industrial or power development firms.

Education: MBA – Finance, Pace University
BS Mechanical Engineering, Manhattan College

2017 Q-1 Report

Parameters:	For Cost Metrics: Holding Period	For Cost Metrics: Confidence	For MtM Metrics: Holding Period	For MtM Metrics: Confidence

	Metrics for Week Ending												
Report Date:	1/6/2017	1/13/2017	1/20/2017	1/27/2017	2/3/2017	2/10/2017	2/17/2017	2/24/2017	3/3/2017	3/10/2017	3/17/2017	3/24/2017	3/31/2017

Where reports include a mix of actual and forecast periods, metrics reflect no risk for settled positions.

Current Gas Year, Annual

Projected Supply Needs:
Hedge Ratio:
Unhedged Ratio:

$/MMBtu, Annual

Portfolio Value
Mark to Market
Cost VaR
MtM VaR
Cost Outlier
MtM Outlier

$000s, Annual

Portfolio Value
Mark to Market
Cost VaR
MtM VaR
Cost Outlier
MtM Outlier

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PARTY: STAFF – (DIRECT)
DESCRIPTION: Michael A. Gettings MAG-2

2017 Q-1 Report

Parameters:	Cost Metrics:	Holding Period	Confidence	MtM Metrics:	Holding Period	Confidence

	Metrics for Week Ending												
Report Date:	1/6/2017	1/13/2017	1/20/2017	1/27/2017	2/3/2017	2/10/2017	2/17/2017	2/24/2017	3/3/2017	3/10/2017	3/17/2017	3/24/2017	3/31/2017
Plus One Gas Year, Annual													
Projected Supply Needs:													
Hedge Ratio:													
Unhedged Ratio:													
$/MMBtu, Annual													
Portfolio Value													
Mark to Market													
Cost VaR													
MtM VaR													
Cost Outlier													
MtM Outlier													
$000s, Annual													
Portfolio Value													
Mark to Market													
Cost VaR													
MtM VaR													
Cost Outlier													
MtM Outlier													

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Plus Two Gas Year

2017 Q-1 Report

Parameters:	Cost Metrics:	Holding Period	Confidence	MtM Metrics:	Holding Period	Confidence

	Metrics for Week Ending												
Report Date:	1/6/2017	1/13/2017	1/20/2017	1/27/2017	2/3/2017	2/10/2017	2/17/2017	2/24/2017	3/3/2017	3/10/2017	3/17/2017	3/24/2017	3/31/2017
Plus Two Gas Year, Annual													
Projected Supply Needs:													
Hedge Ratio:													
Unhedged Ratio:													
$/MMBtu, Annual													
Portfolio Value													
Mark to Market													
Cost VaR													
MtM VaR													
Cost Outlier													
MtM Outlier													
$000s, Annual													
Portfolio Value													
Mark to Market													
Cost VaR													
MtM VaR													
Cost Outlier													
MtM Outlier													

Glossary of Terms

Action Boundaries

Tiered interim tolerance levels that will trigger incremental hedging before risk metrics threaten ultimate tolerances. Tiered action boundaries work this way: hedge as necessary in defense of Boundary #1 up to a 30% hedge ratio (illustrative), then shift to defense of Boundary #2 up to a 50% hedge ratio, etc.

Confidence Level

A specified probability of the likelihood that prospective outcomes might exceed risk estimates. When risk estimates are specified at a 97.5% confidence level, the assertion is that only 2.5% of outcomes will exceed the risk assessment.

Contingent Strategy

A hedge protocol whereby hedging is suspended or modified to constrain loss potential in response to risk conditions that threaten a hedge-loss tolerance.

Cost Outlier

Measured from the customers' perspective, the potential for unfavorable cost outcomes over a specified holding period at a specified confidence level. Cost Outliers equal the current hedged portfolio value plus Cost VaR.

Cost VaR

Measured from the customers' perspective, the potential change in costs over a specified holding period at a specified confidence level.

Defensive Hedging

A hedge protocol whereby hedges are accumulated in response to risk conditions that threaten a cost tolerance or an interim "action boundary"

Dual Tolerances

An attainable, market-compatible pairing of Cost Outliers and MtM Outliers that would be marginally acceptable in the formulation of hedge strategy. For a given strategy, a very tight cost tolerance must allow for greater hedge-loss tolerance and vice versa.

Holding Period

A finite time period for the measurement of potential value migration. The holding period is typically consistent with the hedger's response time. While the hedge horizon might be multiple years, any risk estimate propagated over long time frames would be unmanageable, the holding period facilitates the management of risks in smaller time increments, from one risk assessment to the next.

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Market VaR

The potential change in unhedged market values over a specified "holding period" at a specified "confidence level."

Mark to Market ("MtM")

The difference between market values and hedged values, expressed either as price per MMBtu or aggregate dollars.

MtM Outlier

The potential for unfavorable mark-to-market outcomes over a specified holding period at a specified confidence level. MtM Outliers equal the current portfolio MtM plus MtM VaR.

MtM VaR

The potential change in mark to market over a specified holding period at a specified confidence level.

Programmatic Hedging

A hedge protocol whereby hedges are accumulated on a calendar basis without consideration of transient market conditions. While programmatic protocols could constitute a small part of a risk-responsive strategy, they constitute the entirety of a targeted-volume strategy.

Prompt Month

The first month for which futures contracts trade.

Risk-Responsive Hedge Strategy

A strategy which depends on the measurement of transient risks, with respect to both high cost potential and large hedge loss potential, and utilizes preplanned responses to defend tolerable outcomes.

Targeted-Volume Hedge Strategy

A strategy which depends solely on calendar-based hedge accumulation without measuring transient risk.

Value at Risk ("VaR")

The potential change in value for any position or portfolio over a specified "holding period" at a specified "confidence level." VaR may be expressed in aggregate dollars or value per unit.

Volatility

Volatility is the potential percentage movement in future prices at a specified confidence level over a specified timeframe. For natural gas, when one hears a standardized expression of volatility, it typically refers to the potential for price movements of a specific futures contract or group of contracts over one year at one standard deviation.

EDUCATION:

M.B.A. – Finance; Florida State University, Tallahassee, Fl. 1981
B.S. – Business Administration; Florida State University, Tallahassee, Fl. 1980

EXPERIENCE:

2010-present **Bureau Chief, Finance, Tax, and Cost Recovery, Florida Public Service Commission, Tallahassee, Florida, 32399**

Advise the Commission regarding all aspects of public utility finance, tax, and economics for all utility industries. Oversee the Bureau of Finance, Tax and Cost Recovery supervisors and analysts. Testify as an expert witness as needed. Preside over rate cases assigned to the bureau. Review and recommend legislation, participate in rule making related to finance and taxation, and review and monitor utility security issuances. Member of the bond team comprised of Duke Energy, Florida and Commission personnel assigned in 2016 to structure, market, and issue $1.3 billion of securitized nuclear asset-recovery bonds.

2000-2009 **Project Manager, C. H. Guernsey & Company, Tallahassee, Florida 32309.**

Provided financial and economic research and analysis and consulting services including the provision of expert testimony. Project responsibilities included cost of equity analysis, credit and capital market analysis, merger and acquisition analysis, utility valuation, demand-side management and energy efficiency analysis, financial integrity analysis, territorial disputes, decoupling analysis, automatic adjustment formula analysis, leverage formula analysis, cost of service and rate design, peer analysis, acquisition adjustments, allowance for funds prudently invested, and appropriate regulatory treatment of gains and losses on sale.

2010 and **Principal, Cicchetti & Co., Tallahassee, Florida 32311**

1990-2000 Provided financial research and consulting services, including the provision of expert testimony, in the areas of public utility finance and economics. Subjects addressed included the cost of equity, the overall cost of capital, capital structure, corporate structure, industry structure, regulatory theory, incentive regulation, the credit and capital markets, cross-subsidization, uniform rates, the appropriate treatment of construction work in progress, construction cost recovery charges, and used and useful property.

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DOCKET: 160001-EI EXHIBIT: 74
PARTY: STAFF – (DIRECT)
DESCRIPTION: Mark Anthony Cicchetti MAC-1

1990 - 2000 **Manager, Arbitrage Compliance, Florida Division of Bond Finance, Tallahassee, Florida**

Was responsible for assuring $16 billion of State of Florida tax-exempt securities remained in compliance with the federal arbitrage requirements enacted by the Tax Reform Act of 1986. Designed and implemented the first statewide arbitrage compliance system which included data gathering, computation, and financial reporting subsystems. Provided investment advice and analysis to trust fund administrators on how to maximize yields while remaining in compliance with the federal arbitrage regulations. In 1999 and 2000, informed responsible parties how they could restructure advanced refunding escrow accounts that resulted in over $1 million of additional earnings. In 2000, obtained a favorable private letter ruling from the IRS regarding temporary investments which resulted in over $10 million of cash savings.

PROFESSIONAL ACTIVITIES:

Secretary/Treasurer – Society of Utility and Regulatory Financial Analysts (Present)
Board of Directors - Society of Utility and Regulatory Financial Analysts (1989 - 1995)
President - Society of Utility and Regulatory Financial Analysts (1992 - 1994)
Secretary/Treasurer - Society of Utility and Regulatory Financial Analysts (1990 - 1992)
Certified Rate of Return Analyst, (1992)
3rd Place, Competitive Papers Session, sponsored by Public Utilities Reports, Inc. in conjunction with the University of Georgia and Georgia State University. September, 1986
Meritorious Service Award, computer revenue requirement modeling, Florida Public Service Commission. October, 1986

ARTICLES AND PUBLICATIONS:

"Gas Distribution: Now a Higher-Risk Business," *Public Utilities Fortnightly,* September 1, 2002.

"Irregular Incentives," *Public Utilities Fortnightly*, June 15, 1993.

"The Quarterly Discounted Cash Flow Model, Effective and Nominal Rates of Return, and the Determination of Revenue Requirements for Regulated Public Utilities," *National Regulatory Research Institute Quarterly Bulletin*, June 1989.

"Adjustments to the Capital Structure: Pro-Rata versus the Tracing of Funds," FPSC Working Paper, March 1986.

"Reconciling Rate Base and Capital Structure: The Balance Sheet Method," *Public Utilities Fortnightly,* June 27, 1985.

Henry Hub Natural Gas Spot Price (Dollars per Million Btu)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1997	3.45	2.15	1.89	2.03	2.25	2.20	2.19	2.49	2.88	3.07	3.01	2.35
1998	2.09	2.23	2.24	2.43	2.14	2.17	2.17	1.85	2.02	1.91	2.12	1.72
1999	1.85	1.77	1.79	2.15	2.26	2.30	2.31	2.80	2.55	2.73	2.37	2.36
2000	2.42	2.66	2.79	3.04	3.59	4.29	3.99	4.43	5.06	5.02	5.52	8.90
2001	8.17	5.61	5.23	5.19	4.19	3.72	3.11	2.97	2.19	2.46	2.34	2.30
2002	2.32	2.32	3.03	3.43	3.50	3.26	2.99	3.09	3.55	4.13	4.04	4.74
2003	5.43	7.71	5.93	5.26	5.81	5.82	5.03	4.99	4.62	4.63	4.47	6.13
2004	6.14	5.37	5.39	5.71	6.33	6.27	5.93	5.41	5.15	6.35	6.17	6.58
2005	6.15	6.14	6.96	7.16	6.47	7.18	7.63	9.53	11.75	13.42	10.30	13.05
2006	8.69	7.54	6.89	7.16	6.25	6.21	6.17	7.14	4.90	5.85	7.41	6.73
2007	6.55	8.00	7.11	7.60	7.64	7.35	6.22	6.22	6.08	6.74	7.10	7.11
2008	7.99	8.54	9.41	10.18	11.27	12.69	11.09	8.26	7.67	6.74	6.68	5.82
2009	5.24	4.52	3.96	3.50	3.83	3.80	3.38	3.14	2.99	4.01	3.66	5.35
2010	5.83	5.32	4.29	4.03	4.14	4.80	4.63	4.32	3.89	3.43	3.71	4.25
2011	4.49	4.09	3.97	4.24	4.31	4.54	4.42	4.06	3.90	3.57	3.24	3.17
2012	2.67	2.51	2.17	1.95	2.43	2.46	2.95	2.84	2.85	3.32	3.54	3.34
2013	3.33	3.33	3.81	4.17	4.04	3.83	3.62	3.43	3.62	3.68	3.64	4.24
2014	4.71	6.00	4.90	4.66	4.58	4.59	4.05	3.91	3.92	3.78	4.12	3.48
2015	2.99	2.87	2.83	2.61	2.85	2.78	2.84	2.77	2.66	2.34	2.09	1.93
2016	2.28	1.99	1.73	1.92	1.92	2.59	2.82	2.82				

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Release Date: 9/21/2016

Source: Energy Information Administration

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 75
PARTY: STAFF – (DIRECT)
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ATTACHMENT A

PROPOSED RESOLUTION OF ISSUES
DOCKET NO. 011605-EI
AUGUST 9, 2002

Components of Proposed Resolution:

1. Each investor-owned electric utility recognizes the importance of managing price volatility in the fuel and purchased power it purchases to provide electric service to its customers. Further, each investor-owned electric utility recognizes that the greater the proportion of a particular fuel or purchased power it relies upon to provide electric service to its customers, the greater the importance of managing price volatility associated with that energy source.

2. Each investor-owned electric utility shall submit to the Commission, at the time of its projection filing in the fuel and purchased power cost recovery docket each year, its risk management plan for fuel procurement. For purposes of this proposed resolution, each risk management plan shall address the following items set forth in Exhibit TFB-4 to the prefiled testimony of Todd F. Bohrmann in this docket: item numbers 1, 3 (to the extent possible), 4, 5, 6, 7, 8, 9, 13, 14, and 15. The information provided as part of each risk management plan should emphasize the utility's numerical assessment of an acceptable level of price risk for each type of fuel and for purchased power, the method used to determine the acceptable level of risk, identification of the mechanisms to mitigate risk above the acceptable level, and a valuation of that risk in dollars, where possible. The information provided as part of each risk management plan shall include the quantities of fuel and purchased power that each utility expects to hedge through physical and financial hedging, to the extent such forecasts are made. Filing of such risk management plans for informational purposes shall not constitute approval or disapproval by the Commission. In addition, each investor-owned electric utility shall submit, as part of its final true-up filing in the fuel and purchased power cost recovery docket each year, a report indicating the success of its risk management activities with respect to the objectives set forth in its risk management plan.

3. Each investor-owned electric utility shall be authorized to charge/credit to the fuel and purchased power cost recovery clause its non-speculative, prudently-incurred commodity costs and gains and losses associated with financial and/or physical hedging transactions for natural gas, residual oil, and purchased power contracts tied to the price of natural gas. Examples of such items include transaction costs associated

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ATTACHMENT A

with derivatives (e.g., fees and commissions), gains and losses on futures contracts, premiums on options contracts, and net settlements from swaps transactions. Each utility choosing to engage in such transactions shall maintain records of each transaction for Commission audit purposes.

4. Each investor-owned electric utility may recover through the fuel and purchased power cost recovery clause prudently-incurred incremental operating and maintenance expenses incurred for the purpose of initiating and/or maintaining a new or expanded non-speculative financial and/or physical hedging program designed to mitigate fuel and purchased power price volatility for its retail customers each year until December 31, 2006, or the time of the utility's next rate proceeding, whichever comes first. The base period for determining incremental expenses as described above is the year 2001 (using actual expenses), except for utilities with rates approved based on Minimum Filing Requirements (MFR) in rate reviews conducted since 2001, in which case the projected rate year is the base period (using projected expenses). For purposes of calculating the incremental operating and maintenance expenses for applicable periods of either the initiating or terminating year of this fuel clause recovery arrangement, the corresponding period in the base year shall be the basis for determining recoverable incremental expenses. In September of each year from 2002 through 2006, as part of the Projected Fuel Filing, each utility shall provide an itemization of the projected operating and maintenance expenses for the projected period by functional category for which fuel cost recovery is requested (the incremental expense). Such itemizations shall include allocations, where appropriate, of such costs between financial and physical hedging expense. All base year and recovery year FERC subaccount operating and maintenance expense amounts associated with financial and physical hedging activities shall be included in the Fuel Clause Final True-up filing each April during the years 2003 through 2007, including the difference between the base year and recovery year expense amounts, then summed, yielding a total incremental hedging amount which may be compared for cost recovery review purposes to the requested cost recovery amount produced in the Projected Filing for the recovery year.

5. Each investor-owned utility shall provide, as part of its final true-up filing in the fuel and purchased power cost

ATTACHMENT A

recovery docket, the following information: (1) the volumes of each fuel the utility actually hedged using a fixed price contract or instrument; (2) the types of hedging instruments the utility used, and the volume and type of fuel associated with each type of instrument; (3) the average period of each hedge; and (4) the actual total cost (e.g., fees, commissions, options premiums, futures gains and losses, swaps settlements) associated with using each type of hedging instrument.

6. This proposed resolution is intended to resolve all issues remaining for consideration in this docket, including disposition of the hedging incentive programs proposed in this docket by Florida Power Corporation and Florida Power & Light Company. No party to this docket shall seek approval of a hedging incentive program earlier than the time of its projection filing for the 2004 fuel and purchased power cost recovery period. This proposed resolution is not intended to apply to Florida Public Utilities Company.

7. This proposed resolution may be executed in counterparts, and all such counterparts shall constitute one instrument binding on the signatories, notwithstanding that all signatories are not signatories to the original or the same counterpart. Facsimile transmission of an executed copy of this Agreement shall be accepted as evidence of a party's execution of the Agreement.

* The Commission will review the prudence of each IOU's hedging transactions, including financial hedging transactions, as part of its annual fuel and purchased power cost recovery proceedings. Prudence shall be determined under established legal standards.

* No implication concerning the relative merits of using financial versus physical hedging techniques should be drawn from this proposed resolution.

* "Speculative" refers to physically and/or financially purchasing more of a commodity than one is expected to consume, or physically and/or financially selling more of a commodity than one owns.

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Utility Hedging Practices

In June 2016 FPSC staff, through NARUC, sent a set of questions to the members of the NARUC Staff Subcommittee on Electricity, in order to obtain current information on other states' hedging practices. A summary of the responses follows.

Connecticut

Connecticut is a deregulated market.

Delaware

Following what it described as "disappointing" results from unrestricted natural gas hedging programs from 2000 to 2008, the Delaware Public Service Commission issued an order modifying future practices. In October 2009 the Commission adopted a non-discretionary hedging program for Delmarva Power & Light Company in which 50 percent of projected purchase requirements and storage injections are to be hedged on a pro rata basis (one-twelfth each month) over the 12-months preceding the month in which the physical gas is to be delivered to customers.

Georgia

From 2007 to 2012, Georgia Power Company was authorized to hedge up to 75 percent of its projected natural gas fuel burn, utilizing a 60-month hedging window. In November 2012, the Georgia Public Service Commission amended its hedging program by instituting budget caps so that the total of option premiums and net settlements from financial positions would not exceed hard caps. The caps were set at $45 million (2013), $40 million (2014), and $30 million for 2015 and 2016. In December 2015, at the request of Georgia Power Company the Georgia Commission modified its hedging program, eliminating hard caps, allowing Georgia Power Company to hedge up to 50 percent of its projected natural gas fuel burn in any given month and granted a 48-month hedging window.

Illinois

Illinois electric markets are restructured and, with limited exceptions, load serving entities are free to contract for supply and, in doing so, hedge as they see fit. For customers that do not elect competitive supply and remain on a default bundled service provided by their utility, supply is purchased on behalf of the utility/customer by the Illinois Power Agency (IPA). The IPA does hedge by laddering supply purchases. To a lesser extent, there is also choice in Illinois gas markets and suppliers of gas transportation customers are permitted to hedge at their discretion. Gas utilities that purchased gas on behalf of their customers are also permitted to hedge. Gas utilities have hedged since 2000 and continue to hedge through a broad array of financial hedging tools as well as making use of gas storage. Gas utilities typically discuss their hedging with ICC Staff annually. Gas hedging activities are not made publicly available. Hedging practices are subject to prudence evaluations in each utility's annual fuel costs reconciliation.

Kentucky

In March 2015, the Kentucky Public Service Commission denied Duke Energy's request to continue its hedging program. The Kentucky Commission determined customer benefits were not significant enough to justify extension of the hedging program.

Louisiana

The Louisiana Public Service Commission is developing a long-term natural gas hedging pilot program. Under what is expected to be a three-year pilot program, investor-owned utilities (IOUs) would be required to consider a range of long-term gas procurement strategies. The Louisiana Commission found that most of the state's IOUs purchased a substantial amount of natural gas through short-term contracts, which it determined to be a higher risk strategy.

Minnesota

The three largest natural gas utilities are allowed to use physical contracts and financial instruments for hedging purposes. The requests (petitions) are for variances to the Minnesota Public Service Commission rules that apply to purchased gas adjustment (PGA) cost recovery mechanisms. The rule variances allow cost recovery through the automatic cost recovery mechanisms (riders) even though hedging costs are not defined in these rules as a cost of gas.

The Commission has generally accepted reduction in price volatility as a reasonable goal. However, the Commission has not specifically required hedging or, on the other hand, disallowed recovery of any costs associated with hedging. Cost recovery for hedging is typically allowed when the hedging activity stays within prescribed guidelines that are set in advance on a case-by-case basis at the utilities' request.

Nevada

The Nevada Commission ended hedging programs citing declining price volatility.

New York

New York state's major electric utilities are not vertically integrated and generally purchase power from the New York Independent System Operator or through bilateral contracts. As a result, the utilities generally do not hedge fuel, but instead hedge their market purchases, primarily through financial contracts such as swaps and options. The New York Public Service Commission (NYPSC) requires the major electric (and gas) utilities to mitigate the supply price volatility only for their full service mass market customers, i.e. those residential and small non-residential customers that opt to purchase supply from the utility rather than a competitive Energy Service Company. The utilities are not allowed to hedge for their larger non-residential customers, although the majority of such customers opt to receive their supply from competitive energy service companies.

North Carolina

As the electric utilities in North Carolina started adding significant amounts of gas-fired generation, the North Carolina Utilities Commission encouraged the utilities to consider hedging natural gas purchases to manage the volatility of natural gas prices. The Commission does not require hedging and has not established hedging policies for the utilities to follow. Instead, the prudency of all fuel costs incurred, including hedging costs, are subject to review in the annual fuel charge adjustment proceedings for each utility. To date, the utilities have been allowed to recover the natural gas hedging-related costs that have been incurred.

Oregon

In March, 2015, the Public Utility Commission of Oregon opened a docket to explore the benefits and risks of the long term hedging policies of Northwest Natural Gas Company. The docket remains open at this time.

Washington

The Washington Utilities and Transportation Commission allows hedging. The Commission does not have explicit policies on hedging; however, companies are expected to act in a prudent manner in making fuel or gas purchases.

Companies serving Washington's ratepayers mainly use a programmatic approach in their hedging, i.e., purchasing physical or financial futures contracts systematically prior to the delivery date, which is normally within one-year of its expected need. The Washington Commission has an active docket on gas hedging and is working with a consultant to reassess the state's energy utilities' current approach.

Published on *Fortnightly* (http://www.fortnightly.com)

The new world of gas supply, brought about by shale development, the economic downturn, and expanded gas infrastructure, has caused regulatory stakeholders to challenge utility gas supply hedging programs.

Hedging, a common feature of utility risk management practices, serves as a tool to stabilize prices, protect customers from market volatility, and insure against unexpected price spikes. However, regulatory commissions and intervenors are challenging the merits of their utilities' hedging programs with increasing frequency, questioning whether the risk mitigation benefits of hedging
have justified the associated costs, and whether customers are paying for insurance to manage a risk that might no longer exist.

Concerns raised by commission staff or other stakeholders relating to the cost of utility hedging programs has led to an emerging trend of greater commission and stakeholder involvement in assessing such programs' efficacy. Regulatory commissions are asking utilities to provide written justification of their hedging practices, applying pressure on utilities to work with stakeholders to resolve hedging differences through collaborative processes and to find common ground on the risk-reward spectrum. In some cases, risk management hedging programs have been suspended until there are visible increases in volatility and market prices.

Utilities that engage stakeholders in a dialogue now about their risk-management practices can ensure hedging remains a viable tool for limiting exposure to future price volatility.

Costs Incurred and Avoided

This shift toward re-assessing hedging practices is relatively recent. In 2008, a survey conducted by the National Regulatory Research Institute (NRRI) indicated that most commissions in the U.S. either supported or were neutral to hedging.[1] This was reinforced in a follow-up survey the AGA conducted in 2009.[2] Among more than 100 respondents, over 90 percent said their commissions allowed financial hedging of commodity price risk. However, only a very small number of commissions required utilities to engage in financial hedging.

Push-back on utility hedging typically begins with intervenors. Ultimately, however, most administrative law judges and commissions generally support hedging. While intervenors often recommend disallowance of hedging costs, commissions generally accept that the goal of hedging is price stability and not "to beat the market." As a result, cost disallowance decisions by commissions have been rare.[3] But, in an environment where utility customers are experiencing across-the-board rate increases, it isn't surprising that commissions would encourage utilities to evaluate changes to their hedging programs.

Intervenors have tended to take a retrospective view when evaluating the efficacy of hedging programs. While it's tempting to look at historical hedging based on current information and perfect hindsight, the regulatory standard for what is reasonable and prudent must consider the availability of information and what was known at the time hedging decisions were made. This is the standard commissions have adopted when reviewing historical hedging costs.

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PARTY: STAFF – (DIRECT)
DESCRIPTION: Mark Anthony Cicchetti MAC-5

Many stakeholders have focused on costs associated with hedging, but there has been less focus by all parties on avoided cost analysis. In several instances, success—or lack thereof—has been measured by comparing the hedged prices to spot market prices. The costs have included net premiums paid for call options, as well as the difference between the fixed price or option strike price and the spot market price. There is often a failure to see the cost of options as an insurance premium, as well as to consider a fixed price as a rate stabilization tool. Further, what's missing is
more analysis of the potential avoided cost. Additional scenario analysis would demonstrate the risk of what could have occurred as well as estimate the potential price exposures avoided as a result of hedging.

Additionally, some stakeholders raise the concept of "least cost" in hedging program critiques. Care must be exercised when applying the least-cost principle to hedging, which presents trade-offs in risk, reward, and costs, depending upon the hedging instrument. Using the analogy of insurance, it is possible to buy an inexpensive policy with a low premium, but this is usually accomplished by increasing the deductible, placing a cap on the total payout, or carving out conditions under which benefits aren't paid. Additionally, different hedging strategies yield different benefits, depending on market price direction. For example, if a utility is purchasing energy in a rising-price market, a fixed price purchase might be optimal as there is no option payment incurred and the coverage starts immediately. In a range-bound market, a costless collar might be the lowest cost of insurance, and in a declining market, a cap at a relatively high strike might be the most attractive form of hedge protection.

The Shale Gas Factor

A review of comments filed by commission staff and other stakeholders shows that shale gas development is repeatedly referred to as a "game changing" technology. Shale gas producers access prolific geological deposits of reserves for production at relatively low costs, which has led to significantly dampened price volatility and lower market prices.

While the emergence of shale gas production is generally well-known by intervenors and regulators, the broader market dynamics are less well understood. Equally important is the fact that new pipeline infrastructure has served to deliver shale gas supplies into what historically have been transportation-constrained end markets, thereby changing traditional basis-pricing relationships and further easing price volatility. Additionally, new LNG import facilities and expansions in natural gas storage capacity in recent years have contributed to expanded supply capacity. These supply and capacity additions have occurred at the same time that demand has declined. On the demand side, increasing energy efficiency measures and declining demand resulting from weak economic conditions have dampened consumption.

However, history repeatedly has shown that commodity market conditions are never stagnant, and that markets often correct as supply and demand factors re-balance. The recent 24 months of price declines have lulled many stakeholders into believing that low gas prices are now the norm, but market conditions will change at some point. The question is when, how quickly, and to what degree? If we have learned anything from the past, it is that we cannot predict the future with certainty. In the future, changing supply-demand factors might turn market prices in the other direction.

Utilities will want to be prepared before a market shift occurs. On the supply front, there might be environmental regulation that slows shale gas production, additional compliance requirements that increase shale gas production costs, or technical factors that reduce the projected size of economical reserves. Natural gas demand might increase due to stymied nuclear plant development, rising coal plant operating costs, or closures of coal plants as a result of environmental compliance. New demand could result from economic recovery, LNG exports, or new natural gas and electric vehicle use. A combination of these factors could cause the North American

gas supply-demand balance to materially shift, bringing about increases in market prices and volatility.

As market prices have dropped, many stakeholders are encouraging utilities to adapt their hedging practices to the current market supply and pricing paradigm. Some have suggested utility hedging be reduced until such time as gas market prices show some sign of rallying. Others are taking a more proactive stance, encouraging longer-dated hedging and new hedging program design.

Two commissions that recently have suspended hedging activities are the Public Utilities Commission of Nevada (December 2010), with respect to Nevada Power, and the British Columbia Utilities Commission (July 2011), in regard to FortisBC. The commissions didn't disallow previously executed hedge transactions, and they left existing hedges in place; the decisions applied to future hedging activity.

In its Dec. 16, 2010 order (Docket No. 10-09003), the Nevada PUC approved a stipulation that included the requirement that Nevada Power not proceed with any additional financial gas hedges. However, the utility was told it should continue reviewing natural gas hedging in light of prevailing market fundamentals and conditions.[4] More recently, on July 22, 2011, the British Columbia Utilities Commission rejected FortisBC's "Price Risk Management Plan." In the order, the Commission
Panel wrote: "in light of the recent exploitation of shale gas, the likelihood for more stable natural gas prices is significantly greater and the risk of dramatically higher natural gas prices, excepting short periods of price disconnects, is significantly lower than it has been in many years."[5] Further, the panel suggested that hedging was not the best way to deal with the potential for price
increases, but commented that if there were a change in market conditions, they would be willing to consider proposals to mitigate price risks for customers. They concluded by saying that the performance of the utility's "Price Risk Management Plan" over the last 10 years did not convince them that continuation of the program was in the ratepayers' interest.

Measuring Prudence

Hedging programs are undergoing a greater degree of regulatory scrutiny. In some instances, hedging programs have been scrutinized and continued without modification, while in other cases, hedging programs have been targeted for additional review.

In spring 2009, the Colorado Public Utilities Commission commented on testimony filed by commission staff, which criticized gas hedging by Xcel's subsidiary, Public Service Company of Colorado. The staff had conducted a quantitative analysis to determine that during the period following Hurricane Katrina (2005-2006), the utility's hedges were close to breaking even, *i.e.*, the premium paid for hedging nearly equaled the benefits it provided over spot market prices. But a break-even analysis of the hedging costs compared to spot market prices for the period 2005 to
2008 illustrated that the utility only regained approximately one third of every dollar spent on hedging. Ultimately, in its order, the commission supported the administrative law judge's position that the utility's hedging program should not be suspended. In his recommended decision, the judge wrote, "Preapproved elements of the [hedging] plan avoid hindsight evaluation of each program. Simply stated, [the plan] is to be evaluated based upon information available at the time, not in
terms of whether the plan 'beat the market.' To the extent Public Service implements such a plan, as approved, the associated hedging costs should not be subject to disallowance in any subsequent gas cost prudence review proceedings."[6]

In another example, a commission decided to open a utility's hedging program to further review. In May 2011, in response to PacifiCorp's rate filing for Rocky Mountain Power, the Utah Industrial Energy Consumers filed direct testimony asking the Utah Public Service Commission to disallow
$19.7 million in revenue requirements related to what the group called "imprudent hedging

practices" by the utility. Rocky Mountain Power's hedging program layered-in hedges 48 months into the future, hedging nearly 100 percent of its open commodity price risk. In the industrial group's testimony, it commented that the utility's hedging program wasn't adjusted to account for changes in market conditions and the expanding supply of natural gas through shale gas production.[7] Hence, the industrial group suggested the utility was imprudent to hedge such a large percentage of its open positions and should have reduced its fixed-price hedges, to leave open one-third of its portfolio to spot market pricing.

In July 2011, a stipulation was filed with the Utah PSC where the parties agreed to a collaborative process to review possible changes to the company's hedging practices. As part of the stipulation, it was agreed that the utility's past hedges wouldn't be disallowed, but that the utility would implement any changes that result from the collaborative process or commission order. Issues addressed in the collaborative process included: a new maximum hedge volume percentage limit or range; risk tolerance bands based on time-to-expiry value-at-risk (TEVaR) or value-at-risk (VaR) limits; position limits; a process for review of hedging transactions outside of accepted guidelines, including natural gas reserves or storage; liquidity, transparency, and other risks of different hedging tools such as financial swaps, fixed-price physical forward contracts, and options; a semi-annual confidential report on hedging status; and coordination and implementation issues relating to the inclusion of financial swap transactions in Rocky Mountain Power's energy balancing account.[8] The stipulation was approved in a commission order on Sept. 13, 2011, and PacifiCorp and the other stakeholders were expected to complete discussions by January 2012.

In February 2011, the South Carolina Office of Regulatory Staff (ORS) requested suspension of the hedging programs of South Carolina Electric and Gas (SCE&G) and Piedmont Natural Gas. The ORS commented that the hedging costs incurred by the utilities might be appropriate for markets where there is significant price volatility, but were not appropriate for more stable natural gas market conditions. According to the ORS, SCE&G's hedging program cost customers more than $50 million since 2006, and Piedmont's program cost over $37 million since 2002.[9] This request for suspension was later withdrawn in July 2011, and it was determined that the utilities and the ORS would address the prudence of the hedging activities in each of the companies' respective annual purchased gas adjustment (PGA) proceedings.[10]

In SCE&G's PGA proceeding, the ORS evaluated the company's hedging program and affirmed its previous recommendation that the hedging program should be suspended. SCE&G agreed to immediately suspend all hedging until the commission directs it to recommence. The agreement anticipates that changing market conditions—*e.g.*, environmental restrictions on shale gas production—could warrant a resumption of hedging.[11] Conversely, Piedmont's hedging program was approved in its PGA proceeding with the removal of its previously established minimum hedging requirement of 22.5 percent. Although Piedmont's gas purchasing and hedging activities were deemed to be prudent, there was disagreement on whether gas purchasing and hedging activities, pursuant to a commission-approved hedging program, should be subject to an after-the- fact prudence determination. The commission requested an *ex-parte* briefing on the issue of how to measure prudency in hedging programs.[12]

Strategic Adaptation

In some jurisdictions, regulators are modifying the hedging program horizon and limiting discretionary actions. In Delaware, Delmarva Power has a programmatic hedging program with periodic hedging at pre-determined intervals. In 2009, the utility reduced the tenor and the total volume of hedging. More recently, in response to Delmarva Power's "Gas Cost Rate" filing, a consultant for the commission staff proposed two alternative hedging strategies to enhance flexibility in the hedging framework and to provide a greater smoothing effect on gas price spikes.

The consultant recommended either lengthening the "hedging interval" beyond 18 months to take advantage of lower volatility in outer months; or implementing dollar cost averaging,[13] with fixed dollars allocated for hedges rather than fixed volumes, so that hedging volumes would increase in low-priced market environments and would decrease in higher-priced market environments. The consultant stated that dollar cost averaging results in lower gas costs when compared to a less- flexible, programmatic hedging strategy.[14] Although no changes were made to Delmarva Power's gas hedging program, the company agreed to review and discuss the staff consultant's recommendations for modification.[15]

In Michigan, intervenors in the Consumers Energy rate case proposed a range of changes to reduce the volume and tenor of hedging under the utility's fixed-price hedging program to address concerns that the utility was over-hedging with fixed-price purchases. In that proceeding, intervenors urged the commission to eliminate the "tiered" strategy, which provided for programmatic purchases of fixed price supply in accordance with monthly hedge targets, and suggested modifications to the company's "quartile" strategy, which it had employed in tandem with the tiered strategy, using historical pricing to determine the amount of forward market hedging. All parties proposed a reduction in annual hedging caps. The ALJ decision supported the company's proposed plan, but indicated that certain accelerated purchases under the tiered strategy would require justification by market conditions to be deemed prudent.[16] At this writing, a final decision in this proceeding was pending.

In California, parties to the electric utilities' procurement plan filings are discussing moving from fixed caps on hedging, as determined by the consumer rate tolerance (CRT) of 1 cent per kilowatt hour, to a restructured CRT that represents a percentage of the individual utility's system average rate. By moving to a percentage of the system average rate, the percent hedged under the CRT would remain constant and wouldn't fluctuate with rate changes.[17]

Locking-In for the Long-Term

The Public Utility Commission of Oregon approved a $250 million investment in reserves by its gas utility, Northwest Natural. The utility entered an agreement with Encana Oil & Gas (USA) to develop physical gas reserves expected to supply a portion of the utility customers' requirements over a period of about 30 years, with 8 to 10 percent of Northwest Natural's average annual requirements supplied through the arrangement. The Commission approved the utility's plan in April 2011, allowing the utility to recover the costs of gas produced and delivered, plus a rate-base return on investment through its annual PGA mechanism.[18]

In Colorado, the *Clean Air - Clean Jobs Act* of 2010 (HB 10-1365), included a legislative provision to facilitate fuel-switching from coal to natural gas, while protecting ratepayers from volatility in prices. The provision provides regulatory certainty that utilities will be allowed full cost recovery, without risk of future disallowance, for commission-approved, long-term gas contracts—of between three and 20 years in duration—entered into pursuant to the act.[19] To that end, Public Service Company of Colorado and Anadarko entered a 10-year, fixed-price gas supply agreement, subject to annual price escalations, that is projected to result in savings to ratepayers of approximately $97 million, when compared to forecast gas costs without the contract.[20]

Black Hills Energy of Colorado has incorporated a long-term hedging strategy into its "Gas Mitigation Plan." The plan provides for hedging between 50 and 70 percent of its gas requirements under normal conditions, with the remaining gas requirements purchased in the monthly or daily spot market. Of the hedged volumes, half are comprised of fixed-price swaps phased in over three separate terms: three years, five years, and seven years. The long-term hedges, once fully phased- in, will represent approximately half of the company's normal annual volume requirements. Another

20 percent of the gas supply requirements are hedged using call options in a short-term hedging strategy for the upcoming year.[21]

Commissions will continue to review their utilities' hedging plans in a critical light, and it will be necessary for utilities to work in collaboration with stakeholders to consider adaptations to hedging plans that respond to new market conditions and that protect customers in the event of rising gas and power prices.

Window of Opportunity

Hedging objectives are an important part of the dialogue between commissions and utilities, and avoided costs need to be considered in developing a hedging program. "Hedging" can mean different things to different parties. Therefore, an important first step is to obtain broad consensus about the objectives of the utility's hedging program. By way of simple example, one objective could be that hedging is intended to protect customers against price spikes during certain high usage seasons, while another objective might be to protect customers against rising price trends that could occur over an extended period of time.

One benefit arising from the increased focus on utility hedging is that regulators and stakeholders have grown increasingly sophisticated about commodity markets and hedging, and some might support more complex programs in the future. However, the more discretionary a program design, the more critical decisional documentation and transparent processes become. Further, there must be rigor and consistency in how hedging is adjusted in different market price environments. It will be important in the design and approval stage that the hedging program has clear triggers for when hedging decisions will be executed. During the implementation stage, it will be important for utilities to document information that was known to them at the time hedges were transacted to demonstrate that reasonable actions were taken, consistent with the program design.

It is somewhat ironic that in today's market, as the price of hedging has declined, stakeholder support for hedging has waned. The low-price and low market-volatility environment introduces opportunities to execute hedges at historically attractive price levels. If utilities were to abstain from hedging until volatility increased and market prices rose, the cost of hedging would increase to the point where hedging could be deemed by regulators to be too costly for ratepayers.

In jurisdictions where intervenors and perhaps regulators might be reluctant to support an expansive hedging program at current lower market prices, utilities should use a collaborative process to garner support. The first objectives would be to improve stakeholders' understanding of the supply-demand market fundamentals that have contributed to current lower prices, and to explain future trends and events that could move market prices upward. A better understanding of market drivers and how prices could potentially change will help stakeholders appreciate the utility's need to be ready with hedging strategies to protect customers from rising wholesale market prices.

The second objective would be to engage stakeholders in a dialogue about how the utility's current hedging program was developed, and to listen to stakeholders' concerns. Working collaboratively, it is possible for all the parties to bring a fresh perspective to the hedging program and consider how it might be adapted under varied market conditions. Such efforts will yield the greatest benefit for utilities and their customers if they happen before supply-demand conditions materially change market prices, and the current window of opportunity closes.

Endnotes:

1. National Regulatory Research Institute, *NRRI Services: Survey on State Commission and Local Gas Distribution Company Actions in Addressing High Natural Gas Prices*, (July 3, 2008).

2. Bruce McDowell, *AGA Rate Inquiry: Regulatory Hedging Policies*, American Gas Association, (Fall 2009).

3. In a recent commission order (Docket No. UE 228), the Public Utility Commission of Oregon penalized Portland General Electric (PGE) for failure in 2007 to document the reasons for executing 2012 gas hedges. In its decision, the Commission noted its 2002 order (in Docket No. UE 139) in which the commission disallowed costs associated with certain of PGE's forward power purchases citing the company's failure to provide evidence regarding price trends or internal company market analyses that might have supported the reasonableness of the company's decisions. In its decision in UE 228, the commission reduced the utility's 2012 net variable power costs forecast by $2.6 million "to ensure management's future compliance" with commission orders. The penalty was calculated as the monetary equivalent of a one-year, 10-basis-point reduction in PGE's authorized return on equity. Public Utility Commission of Oregon, Docket No. UE 228, *2012 Annual Power Cost Update Tariff*, (Nov. 2, 2011).

4. Public Utilities Commission of Nevada, Docket No. 10-09003, *Application of NV Power Co d/b/a NV Energy for Approval of its Energy Supply Plan Update for 2011-2012*, Order (Dec. 16, 2010) and Stipulation (Nov. 9, 2010). Note, in September 2011, Nevada Power submitted a proposal to engage in new hedging, using out-of-the-money call options in its filing to the Public Utilities Commission of Nevada, *Application of Nevada Power Company d/b/a NV Energy for Approval of its Energy Supply Plan Update for 2012*, Docket No. 11-09003, (Sept. 1, 2011). However, in its draft order in the same docket, dated Dec. 14, 2011, the commission rejected NV Energy's hedging proposal and ordered NV Energy to continue the existing commission-approved hedging strategy described in the stipulation that the commission approved in Docket No. 10-09003 on Nov. 9, 2010, without exception.

5. British Columbia Utilities Commission, Order Number 6-120-11, *Application by Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. (collectively Terasen Gas) (now FortisBC Energy Inc. and FortisBC Energy (Vancouver) Inc.) for Approval of the Price Risk Management Plan Effective April 2011-October 2014*, (July 12, 2011).

6. Public Utilities Commission of the State of Colorado, Docket No. 08A-095G, *In the Matter of the Application of Public Service Company of Colorado for Authorization to Continue in Effect, On a Permanent Basis, Its Monthly Gas Cost Adjustment Tariffs, With Modifications to provide For Symmetrical Interest on Deferred Balanced of Over- And Under-Recovered Gas Costs, and to Extend For an Additional Four-Year Period the Current Procedures for Seeking and Obtaining Authorization to Implement Annual Gas Price Volatility Mitigation Plans for Its Gas Sales Customers*, (March 2, 2009).

7. Public Service Commission of Utah, Docket No. 10-035-124, Direct Testimony of J. Robert Malko, Utah Industrial Energy Consumers, *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, (May 26, 2011).

8. Public Service Commission of Utah, *Rocky Mountain Power Settlement Stipulation, (July 28, 2011) and report and order, Rocky Mountain Power 2011 General Rate Case*, Docket Nos. 10-035-124, 09-035-15, 10-035-14, 11-035-46 and 11-035-47, (Sept. 13, 2011).

9. South Carolina Office of Regulatory Staff, *Letter Re.: Request for Suspension of SCE&G and Piedmont Gas Hedging Programs*, Docket No. 2011-82-G, (Feb. 24, 2011).

10. Public Service Commission of South Carolina, Commission Directive, Docket No. 2011-82-G, Order 2011-402, (July 13, 2011).

11. Public Service Commission of South Carolina, Settlement Agreement, *IN RE: Annual Review of Purchased Gas Adjustment and Gas Purchasing Policies of South Carolina Electric & Gas Company*, Docket No. 2011-5-G, (Nov. 2, 2011).

12. Public Service Commission of South Carolina, Order Ruling On Purchased Gas Adjustment And Gas Purchasing Policies, *IN RE.: Annual Review of Purchased Gas Adjustment and Gas Purchasing Policies of Piedmont Natural Gas*, Docket No. 2011-4-G – Order No. 2011-580, (Aug. 17, 2011).

13. Dollar cost averaging is the technique of hedging a fixed dollar amount of a particular commodity on a regular schedule, regardless of the contract price. More contracts are purchased when prices are low, and fewer contracts are purchased when prices are high.

14. Public Service Commission of Delaware, PSC Docket No. 010-295F, Direct Testimony of Richard W. Lelash on behalf of the Staff of the Delaware Public Service Commission, *In the Matter of the Application of Delmarva Power & Light Company for Approval of Modifications to Its Gas Cost*
Rates, (Feb. 10, 2011).

15. Public Service Commission of Delaware, Order No. 8061, *In the Matter of the Application of Delmarva Power & Light Company for Approval of Modifications to Its Gas Cost Rates* (Filed Aug. 31, 2010), PSC Docket No. 010-295F, (Oct. 18, 2011).

16. Michigan Public Service Commission, Case No. U-16485, Notice of Proposal for Decision, ALJ Sharon L. Feldman, *In the Matter of the Application of Consumers Energy Company for Approval of a Gas Cost Recovery Plan and Authorization of Gas Cost Recovery Factors For the 12-Month Period April 2011- March 2012*, (Sept. 12, 2011).

17. California Public Utilities Commission, Rulemaking 10-05-006, *Proposed Decision Approving Modified Bundled Procurement Plans*, Proposed Decision of ALJ Peter Allen, (Nov. 10, 2011).

18. Northwest Natural, Securities and Exchange Commission, 10-Q filing (First Quarter 2011).

19. See Colorado General Assembly H.B. 10-1365, Section 40-3.2-206. Part 4 (signed into law April 19, 2010).

20. *Statement of Position of Public Service Company of Colorado*, in Docket No. 10M-245E, at 72, (Nov. 29, 2010)

21. Direct Testimony of Trent Cozad, Docket No. 11A-580E before the Colorado Public Utility Commission *(Re: Gas Mitigation Plan)*, pp.3-7.

Media:

Source URL: http://www.fortnightly.com/fortnightly/2012/02/hedging-under-scrutiny

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DEF's Response to Staff's Second Set of Interrogatories, Nos. 9-11

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 79
PARTY: STAFF – (DIRECT)
DESCRIPTION: Matthew J. Jones

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 160001-EI DATED: May 18, 2016

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 9-11)

Duke Energy Florida, LLC ("DEF"), responds to Staff's Second Set of Interrogatories to DEF (Nos. 9-11), as follows:

INTERROGATORIES

9. Is the end of month Common Equity balance amount of $5,282,300,994 for January 2015 (Line 2) a system amount or a jurisdictional amount? Explain in your response why a system (or a jurisdictional) amount is appropriate for the purpose of calculating GPIF rewards and penalties.

RESPONSE:

The Common Equity balance is a system amount. The system amount is appropriate because DEF applies a Retail Jurisdictional Factor on line 20 of this schedule. This ensures that the maximum allowable jurisdictional incentive on line 21 is a retail jurisdictional amount. The Jurisdictional Separation Factor (line 20) is calculated as the ratio of Jurisdictional Sales (line 18) out of Total Sales (line 19). This factor is applied on Maximum Allowed Incentive Dollars (line 16) to get Maximum Allowed Jurisdictional Incentive Dollars (line 21).

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10. Please identify the specific source for the Common Equity balance amount of $5,282,300,994 for January 2015 (Line 2 from page 3 of MJJ-1T). If applicable, describe any and all different sources for February 2015 (Line 3) through December 2015 (Line 13) amounts.

RESPONSE:

The source for the Common Equity balance is the Working Trial Balance document which is produced monthly by Duke Energy's financial reporting system (HFM).

11. For the common equity balance that DEF used to calculate its 2015 GPIF reward, please cite the specific order(s) and authority for using that specific common equity balance.

RESPONSE:

In Order No. 9558, the Commission established the Generating Performance Incentive Factor (GPIF). In Appendix A of that order, Section II outlines the calculation of the Maximum Allowed Incentive Dollars. The formula presented in the order specifies the use of the Average Common Equity for the period being evaluated. This formula is further supported in the GPIF Manual, which was approved in Commission Order No. 10168. In the GPIF Manual Sheet 3.400 and Sheet 3.504, DEF is instructed to use the Average Common Equity for the Period. This is the balance DEF calculated and used on page 3 of the 2015 GPIF True-Up Filing.

AFFIDAVIT

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

I hereby certify that on this 5 day of May, 2016, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared MATHEW J. JONES, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 9, 10, and 11 from STAFF'S SECOND SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 9-11) in Docket No. 160001-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 5 day of May, 2016.

KATIE JAMIESON
Notary Public
Mecklenburg County
NORTH CAROLINA

MATTHEW J. JONES

Katie Jamieson
Notary Public
State of North Carolina

My Commission Expires:
June 14, 2016

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DEF's Response to Staff's Fourth Set of Interrogatories, No. 15 (Redacted)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 80
PARTY: STAFF – (DIRECT)
DESCRIPTION: Joseph McCallister

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor	Docket No. 160001-EI Dated: August 29, 2016

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S FOURTH SET OF INTERROGATORIES (NO. 15)

Duke Energy Florida, LLC ("DEF"), responds to Staff's Fourth Set of Interrogatories to DEF (Nos. 15) as follows:

INTERROGATORIES

15. For the purpose of this interrogatory, please complete Table 1 below:

Table 1

Monthly Percent of Natural Gas Volume Hedged in Relation to Total Burned DEF 2013-2016				
	2013	2014	2015	2016
January				
February				
March				
April				
May				
June				
July				
August				N/A
September				N/A
October				N/A
November				N/A
December				N/A
Yearly Average				N/A
Hedging Range for Natural Gas identified in that year's Risk Management Plan				

Answer:

REDACTED

Monthly Percent of Natural Gas Volume Hedged in Relation to Total Burned DEF 2013-2016				
	2013	2014	2015	2016
January	[redacted]			
February				
March				
April				
May				
June				
July				
August				
September				
October				
November				
December				
Yearly Average				
Hedging Range for Natural Gas identified in that year's Risk Management Plan				

Notes:

#1 - Actual burns for periods January 2016 through June 2016. July 2016 burn numbers are considered estimates subject to minor adjustments based on actual bookings.

#2 - DEF's targeted hedging percentage ranges outlined in its Risk Management Plan are based on calendar year forecasted burns (January through December). The volumes hedged over time are based on periodic updated fuel forecasts and the actual hedge percentages for any month, rolling period, or calendar annual period may come in higher or lower than the target minimum hedge percentages and hedging ranges because of actual fuel burns versus forecasted fuel burns. In its Risk Management Plan, DEF outlined the targeted hedge percentages ranges are based on forecasted burns are for calendar year periods. The actual hedge percentages may differ from hedge percentages based on forecasts.

AFFIDAVIT

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

I hereby certify that on this 24 day of August, 2016, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **JOSEPH MCCALLISTER**, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number 15 from STAFF'S FOURTH SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NO. 15) in Docket No. 160001-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 24 day of August, 2016.

JOSEPH MCCALLISTER

Katie Jamieson
Notary Public
State of North Carolina

KATIE JAMIESON
Notary Public, North Carolina
Gaston County
My Commission Expires

My Commission Expires:

June 14, 2021

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DEF's Response to Staff's Fourth Set of Interrogatories, No. 15 (Confidential DN 07080-16)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 81
PARTY: STAFF – (DIRECT)
DESCRIPTION: Joseph McCallister

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DEF's Response to Staff's Amended Fifth Set of Interrogatories, Nos. 16-23

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 82
PARTY: STAFF – (DIRECT)
DESCRIPTION: Joseph McCallister

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor	Docket No. 160001-EI Dated: August 31, 2016

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S AMENDED FIFTH SET OF INTERROGATORIES (NOS. 16-23)

Duke Energy Florida, LLC ("DEF"), responds to Staff's Amended Fifth Set of Interrogatories to DEF (Nos. 16-23) as follows:

INTERROGATORIES

For the purpose of the following Interrogatory Numbers 16-22, please refer to the following:

A. **Attachment B, Components Of A Utility's Fuel Procurement Risk Management Plan, Exhibit TFB-4, attached to Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI ("TFB-4").**

B. **DEF Power Company's Risk Management Plan for 2017, filed on August 4, 2016, in Docket No. 160001-EI ("DEF's 2017 Plan").**

16. TFB-4 (sub-part 1) indicates that a Fuel Procurement Risk Management Plan should include information identifying the overall quantitative and qualitative risk management objectives. Please identify by page and line reference(s) where this is addressed in DEF's 2017 Plan.

Answer:

Please note for responses 16-22, although pagination and the ordering of attachments has changed, DEF's proposed 2017 Fuel Procurement Risk Management Plan (2017 RMP) is largely consistent with prior DEF RMP filings reviewed and approved by the Commission, including most recently in Docket No. 150001-EI.

The overall quantitative and qualitative risk management objectives are outlined on page 2 of DEF's 2017 Fuel Procurement Risk Management Plan (2017 RMP). In addition, further examples of DEF's strategy to fulfill these objectives are outlined in Item 8 on page 17 of the 2017 RMP. Please also see Attachments D, E, and H to DEF's Risk Management Plan.

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17. TFB-4 (sub-part 2) indicates that a Fuel Procurement Risk Management Plan should include information regarding identifying the minimum quantity of fuel to be hedged. Please identify by page and line reference(s) where this is addressed in DEF's 2017 Plan.

Answer:
The minimum quantity of fuel to be hedged expressed in a targeted approximate target hedge percentage for each respective period is outlined on page 3 in the section under the heading Natural Gas in Item 2 in the Fuel Procurement Risk Management Plan.

18. TFB-4 (sub-part 3) indicates that a Fuel Procurement Risk Management Plan should include information identifying and quantifying the general and specific risks a utility may encounter with its fuel procurement. Please identify by page and line reference(s) where this is addressed in DEF's 2017 Plan.

Answer:
DEF identifies and quantifies the general and specific risks it may encounter with its fuel procurement in Item 3, beginning on page 5 of the Fuel Procurement Risk Management Plan.

19. TFB-4 (sub-part 4) indicates that a Fuel Procurement Risk Management Plan should include information describing the oversight of a utility's fuel procurement activities. Please identify by page and line reference(s) where this is addressed in DEF's 2017 Plan.

Answer:
The summary information on the oversight of DEF's fuel procurement activities are included in Item 4 and Item 5 on pages 11 to 16 in DEF's Fuel Procurement Risk Management Plan. Please also see Attachments B, C, E, G, and H.

20. TFB-4 (sub-part 6) indicates that a Fuel Procurement Risk Management Plan should include information describing the utility's corporate risk policy regarding fuel procurement activities. Please identify by page and line reference(s) where this is addressed in DEF's 2017 Plan.

Answer:
The information describing the corporate risk policy regarding fuel procurement activities is in Item 6 on pages 15 and 16 of DEF's Fuel Procurement Risk Management Plan; please also see Attachments referenced on page 16.

21. TFB-4 (sub-part 8) indicates that a Fuel Procurement Risk Management Plan should describe a utility's strategy to fulfill its risk management objectives. Please identify by page and line reference(s) where this is addressed in DEF's 2017 Plan.

Answer:
DEF's strategy to fulfill its risk management objectives in summarized in Item 8 on page 17 of its Procurement Risk Management Plan. Please also reference the discussions in Items 2 (page 2) and 3 (page 5), as well as Attachments D, E, and H.

22. TFB-4 (sub-part 13) indicates that a Fuel Procurement Risk Management Plan should include information describing a utility's reporting system for fuel procurement activities.

a. Please identify by page and line reference(s) where this is addressed in DEF's 2017 Plan.

Answer:
DEF includes summary information describing its reporting system for fuel procurement activities in Item 13 on pages 18 and 19 of its Fuel Procurement Risk Management Plan. Please also see Attachment H.

b. TFB-4 (sub-part 14) indicates that a utility's reporting system for fuel procurement activities should consistently and comprehensively identify all forms of risk associated with fuel procurement activities. Please state by page and line reference(s) where risk identification within the utility's reporting system is addressed in DEF's 2017 Plan.

Answer:
DEF addresses risk identification within the utility's reporting system in its 2017 Procurement and Risk Management Plan in Item 14 page 19.

c. TFB-4 (sub-part 14) indicates that a utility's reporting system for fuel procurement activities should consistently and comprehensively measure all forms of risk associated with fuel procurement activities. Please state by page and line reference(s) where risk measurement within the utility's reporting system is addressed in DEF's 2017 Plan.

Answer:
DEF's systems and applications used to monitor and report risks associated with its fuel procurement activities are summarized in Item 13 and 14 on pages 18 and 19 of its 2017 Plan. Please also see Item 3 (page 5) and Attachments D, E, and H.

d. TFB-4 (sub-part 14) indicates that a utility's reporting system for fuel procurement activities should consistently and comprehensively monitor all forms of risk associated with fuel procurement activities. Please state by page and line reference(s) where risk monitoring within the utility's reporting system is addressed in DEF's 2017 Plan.

Answer:
Please see DEF's response to Staff's Interrogatory 22c.

23. Are the processes and practices for hedging natural gas prices that DEF follows the same processes and practices that are followed by any and all unregulated parent or affiliated companies? Discuss in your response how and why the processes and practices for hedging natural gas prices are alike, or different, between DEF, the regulated entity, and any and all unregulated parent or affiliated companies.

Answer:
With respect to natural gas hedging, DEF does not have any unregulated parent electric or gas or affiliates that purchase natural gas or engage in hedging natural gas. All of DEF's affiliates that consume natural gas are U.S. based regulated electric and gas operations.

AFFIDAVIT

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

I hereby certify that on this 8 day of September, 2016, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **JOSEPH MCCALLISTER**, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 16, 17, 18, 19, 20, 21, 22, and 23 from STAFF'S FIFTH SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 16-23) in Docket No. 160001-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 8 day of September, 2016.

JOSEPH MCCALLISTER

Katie Jamieson

Notary Public
State of North Carolina

KATIE JAMIESON
Notary Public, North Carolina
Gaston County
My Commission Expires

My Commission Expires:

June 14, 2021

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DEF's Response to Staff's Sixth Set of Interrogatories, Nos. 24-27 (Redacted), 28-30

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 83
PARTY: STAFF – (DIRECT)
DESCRIPTION: Joseph McCallister

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor	Docket No. 160001-EI Dated: September 29, 2016

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S SIXTH SET OF INTERROGATORIES (NOS. 24-30)

Duke Energy Florida, LLC ("DEF"), responds to Staff's Sixth Set of Interrogatories to DEF (Nos. 24-30) as follows:

INTERROGATORIES

24. For realized (actual) hedging savings and costs for the twelve months beginning August 1, 2015, and ending July 31, 2016, associated with swap contracts for natural gas, please provide the following information in a schedule format:

a. the transaction date (the date the swap was entered into) for the swap;

b. the fixed price for the swap;

c. the month or period in the future the swap is covering; and

d. the corresponding NYMEX futures price for the future month or period for natural gas on the transaction date of the swap.

Response:

Please see attachments bearing bates numbers DEF-16FL-FUEL-00029 through DEF-16FL-FUEL-00038. The attachments are confidential; redacted versions are attached hereto and unredacted versions have been filed with the Florida Public Service

Commission ("Commission") along with DEF's Request for Confidential Classification dated September 29, 2016.

25. For realized (actual) hedging savings and costs for the twelve months beginning August 1, 2015, and ending July 31, 2016, associated with swap contracts for oil, please provide the following information in a schedule format:

e. the transaction date (the date the swap was entered into) for the swap;

f. the fixed price for the swap;

g. the month or period in the future the swap is covering; and

h. the corresponding NYMEX futures price for the future month or period for natural gas on the transaction date of the swap.

Response:

Please see attachments bearing bates numbers DEF-16FL-FUEL-00039 through DEF-16FL-FUEL-00041. The attachments are confidential; redacted versions are attached hereto and unredacted versions have been filed with the Florida Public Service Commission ("Commission") along with DEF's Request for Confidential Classification dated September 29, 2016.

26. For interrogatory numbers 24 and 25 above, please explain the difference, if any, between the swap fixed price and the corresponding futures or forward price for the future period (the period being hedged) that is greater than 5 percent of the swap fixed price.

Response:

The trading prices represented in responses 24 and 25 are the actual prices at which DEF executed the various transactions. Consistent with prior years, the market prices used for the basis of the comparison are the closing daily settlement market prices for each individual month for the respective trade date of each transaction. DEF used the closing daily settlement market prices, as these prices are the data that is readily available. This simplified method of comparison will result in calculated pricing differences between the prices that DEF executed the various transactions versus the closing market prices on those same days. These differences are due to the timing of when DEF executed the transactions during the trading day and the closing market prices on those days for the respective periods hedged. It is common for commodity prices for the forward time periods to fluctuate, sometimes significantly, throughout a trading day. Thus, there will be differences between closing daily settlement prices for any respective month and period and the price levels that DEF executed the various trades for throughout the trading day. In addition to the timing of trade execution differences, there will also be differences that are caused by transactions that included basis in the transaction price, such as Columbia Gulf Mainline, versus a NYMEX market price which does not include the basis. Additional differences result from comparing individual month closing prices to trades that were executed for multiple time periods such as common seasonal and annual strip periods where the same fixed price was executed for the entire time period.

As can be seen from the comparison utilizing the simplified comparison method, DEF had transactions where the comparison would indicate DEF traded below market and above market. However, DEF always executes transactions at the prevailing market price that exist at the time of the trade during the trading day; the highlighted differences in the Attachments are the result of differences between the market prices that existed at the

time DEF executed the transactions during the course of the trading day and the closing prices used for the comparison as noted above. Additionally, some months of strip trades fell both in the test period and outside the test period which will result in additional differences when calculating percentage variances.

As summarized in Question 24 and 25, with respect to natural gas transactions, DEF did not have any difference between the swap fixed and the corresponding futures or forward price for the future period that was greater than 5 percent of the swap fixed price. With respect to oil transactions, DEF did not have any difference between the swap fixed and the corresponding futures or forward price for the future period that was greater than 5 percent of the swap fixed price.

Market prices for natural gas and fuel oil change within trading days and can experience movements within any given trading day for the respective forward time periods being hedged. As noted previously, DEF always executes trades at the market prices that exist at the time trades are executed within the trading day and all the trades executed for the test period were executed at the prevailing market price that existed at the time of the trade on the respective trading day.

27. For realized (actual) hedging savings and costs for the twelve months beginning August 1, 2015, and ending July 31, 2016, associated with options for natural gas prices, please provide the following information in a schedule format.

a. the transaction date for the option;

b. the option price or premium;

c. the type of option;

d. the time to expiration; and

e. the corresponding futures price, forward price, or comparable market price for the period on the transaction date of the option.

Response:
Please see attachments bearing bates numbers DEF-16FL-FUEL-00042 through DEF-16FL-FUEL-00047. The attachments are confidential; redacted versions are attached hereto and unredacted versions have been filed with the Florida Public Service Commission ("Commission") along with DEF's Request for Confidential Classification dated September 29, 2016.

28. For interrogatory 27 above, please explain the difference, if any, between the option price and the corresponding futures price, forward price, or comparable market price for the future period (the period being hedged) that is greater than 5 percent of the option price.

Response:

The option premium prices represented in response 27 are the actual prices at which DEF executed the various financial option transactions. DEF executes all of its natural gas financial options at the prevailing market price that exists at the time the transactions are executed during the course of the trading day as consistent with previous years. DEF does not have observable market data for the natural gas option prices provided in response 27.

29. For open hedging transactions since August 1, 2015, has DEF experienced any defaults by a counter-party? If yes, please identify the counter-party and explain.

Response:

DEF has not experienced any defaults.

30. Does DEF use firm gas storage for physically hedging the price of natural gas? Please explain your response.

Response:

No. DEF does not use its firm gas storage as a physical hedge against the price of natural gas. DEF utilizes its natural gas storage to provide additional supply reliability, operational balancing and optimization. The company does financially hedge the price for a portion of its gas injections each year.

REDACTED

2015 August - December Swap Hedges

Delivery Month	Trade Date	Instrument	Trade Number	Market	Location	Volume MMBtu	Trade Price ($/MMBtu)	Market Price on Trade Date	Percent Difference from Trade Price	
8/1/2015	7/6/2007	Financial Swap	3223326	IFERC	Henry Hub			$6.8064		
9/1/2015	7/6/2007	Financial Swap	3223326	IFERC	Henry Hub			$6.8472		
10/1/2015	7/6/2007	Financial Swap	3223326	IFERC	Henry Hub			$6.9422		
8/1/2015	7/11/2007	Financial Swap	3223331	IFERC	Henry Hub			$6.7730		
9/1/2015	7/11/2007	Financial Swap	3223331	IFERC	Henry Hub			$6.8139		
10/1/2015	7/11/2007	Financial Swap	3223331	IFERC	Henry Hub			$6.9089		
8/1/2015	7/19/2007	Financial Swap	3223333	IFERC	Henry Hub			$6.9738		
9/1/2015	7/19/2007	Financial Swap	3223333	IFERC	Henry Hub			$7.0148		
10/1/2015	7/19/2007	Financial Swap	3223333	IFERC	Henry Hub			$7.1102		
8/1/2015	8/14/2007	Financial Swap	3223336	IFERC	Henry Hub			$7.1159		
9/1/2015	8/14/2007	Financial Swap	3223336	IFERC	Henry Hub			$7.1547		
10/1/2015	8/14/2007	Financial Swap	3223336	IFERC	Henry Hub			$7.2488		
8/1/2015	8/28/2007	Financial Swap	3223424	IFERC	Henry Hub			$6.8815		
9/1/2015	8/28/2007	Financial Swap	3223424	IFERC	Henry Hub			$6.9303		
10/1/2015	8/28/2007	Financial Swap	3223424	IFERC	Henry Hub			$7.0243		
8/1/2015	9/12/2007	Financial Swap	3223426	IFERC	Henry Hub			$7.2198		
9/1/2015	9/12/2007	Financial Swap	3223426	IFERC	Henry Hub			$7.2537		
10/1/2015	9/12/2007	Financial Swap	3223426	IFERC	Henry Hub			$7.3408		
8/1/2015	9/28/2007	Financial Swap	3223428	IFERC	Henry Hub			$7.0219		
9/1/2015	9/28/2007	Financial Swap	3223428	IFERC	Henry Hub			$7.0461		
10/1/2015	9/28/2007	Financial Swap	3223428	IFERC	Henry Hub			$7.1188		
11/1/2015	9/28/2007	Financial Swap	3223428	IFERC	Henry Hub			$7.4292		
12/1/2015	9/28/2007	Financial Swap	3223428	IFERC	Henry Hub			$7.7346		
8/1/2015	10/3/2007	Financial Swap	3223432	IFERC	Henry Hub			$6.9631		
9/1/2015	10/3/2007	Financial Swap	3223432	IFERC	Henry Hub			$6.9823		
10/1/2015	10/3/2007	Financial Swap	3223432	IFERC	Henry Hub			$7.0495		
8/1/2015	10/19/2007	Financial Swap	3223434	IFERC	Henry Hub			$7.1444		
9/1/2015	10/19/2007	Financial Swap	3223434	IFERC	Henry Hub			$7.1587		
10/1/2015	10/19/2007	Financial Swap	3223434	IFERC	Henry Hub			$7.2159		
11/1/2015	10/19/2007	Financial Swap	3223434	IFERC	Henry Hub			$7.4971		
12/1/2015	10/19/2007	Financial Swap	3223434	IFERC	Henry Hub			$7.7878		
8/1/2015	11/6/2007	Financial Swap	3223439	IFERC	Henry Hub			$7.2196		0.8%
9/1/2015	11/6/2007	Financial Swap	3223439	IFERC	Henry Hub			$7.2340		g for the Strip
10/1/2015	11/6/2007	Financial Swap	3223439	IFERC	Henry Hub			$7.2915		
11/1/2015	11/6/2007	Financial Swap	3223439	IFERC	Henry Hub			$7.5789		
12/1/2015	11/6/2007	Financial Swap	3223439	IFERC	Henry Hub			$7.8758		
8/1/2015	12/10/2007	Financial Swap	3223475	IFERC	Henry Hub			$7.8651		
9/1/2015	12/10/2007	Financial Swap	3223475	IFERC	Henry Hub			$7.6800		
10/1/2015	12/10/2007	Financial Swap	3223475	IFERC	Henry Hub			$7.7396		
8/1/2015	12/27/2007	Financial Swap	3223537	IFERC	Henry Hub			$8.0284		
9/1/2015	12/27/2007	Financial Swap	3223537	IFERC	Henry Hub			$8.0434		
10/1/2015	12/27/2007	Financial Swap	3223537	IFERC	Henry Hub			$8.1031		
8/1/2015	1/9/2008	Financial Swap	3223541	IFERC	Henry Hub			$7.8901		
9/1/2015	1/9/2008	Financial Swap	3223541	IFERC	Henry Hub			$7.9051		
10/1/2015	1/9/2008	Financial Swap	3223541	IFERC	Henry Hub			$7.9649		
8/1/2015	2/13/2008	Financial Swap	3223544	IFERC	Henry Hub			$8.0988		
9/1/2015	2/13/2008	Financial Swap	3223544	IFERC	Henry Hub			$8.1088		
10/1/2015	2/13/2008	Financial Swap	3223544	IFERC	Henry Hub			$8.1687		
8/1/2015	2/29/2008	Financial Swap	3223547	IFERC	Henry Hub			$8.7730		0.6%
9/1/2015	2/29/2008	Financial Swap	3223547	IFERC	Henry Hub			$8.7831		g for the Strip
10/1/2015	2/29/2008	Financial Swap	3223547	IFERC	Henry Hub			$8.8487		
11/1/2015	2/29/2008	Financial Swap	3223547	IFERC	Henry Hub			$9.1337		
12/1/2015	2/29/2008	Financial Swap	3223547	IFERC	Henry Hub			$9.4818		
8/1/2015	4/2/2008	Financial Swap	3223546	IFERC	Henry Hub			$8.7545		1.8%
9/1/2015	4/2/2008	Financial Swap	3223546	IFERC	Henry Hub			$8.7645		g for the Strip
10/1/2015	4/2/2008	Financial Swap	3223546	IFERC	Henry Hub			$8.8445		
11/1/2015	4/2/2008	Financial Swap	3223546	IFERC	Henry Hub			$9.1370		
12/1/2015	4/2/2008	Financial Swap	3223546	IFERC	Henry Hub			$9.5270		
8/1/2015	4/25/2008	Financial Swap	3223550	IFERC	Henry Hub			$9.0415		
9/1/2015	4/25/2008	Financial Swap	3223550	IFERC	Henry Hub			$9.0515		
10/1/2015	4/25/2008	Financial Swap	3223550	IFERC	Henry Hub			$9.1315		
8/1/2015	6/12/2008	Financial Swap	3223552	IFERC	Henry Hub			$10.8195		
9/1/2015	6/12/2008	Financial Swap	3223552	IFERC	Henry Hub			$10.8395		
10/1/2015	6/12/2008	Financial Swap	3223552	IFERC	Henry Hub			$10.9195		
8/1/2015	7/11/2008	Financial Swap	3223567	IFERC	Henry Hub			$10.4585		
9/1/2015	7/11/2008	Financial Swap	3223567	IFERC	Henry Hub			$10.4785		
10/1/2015	7/11/2008	Financial Swap	3223567	IFERC	Henry Hub			$10.5585		
8/1/2015	10/21/2008	Financial Swap	3223569	IFERC	Henry Hub			$7.5490		
9/1/2015	10/21/2008	Financial Swap	3223569	IFERC	Henry Hub			$7.5690		
10/1/2015	10/21/2008	Financial Swap	3223569	IFERC	Henry Hub			$7.8490		
8/1/2015	12/2/2008	Financial Swap	3223742	NYMEX NG L1D	Henry Hub			$7.7480		
9/1/2015	12/2/2008	Financial Swap	3223742	NYMEX NG L1D	Henry Hub			$7.7780		
10/1/2015	12/2/2008	Financial Swap	3223742	NYMEX NG L1D	Henry Hub			$7.8580		
8/1/2015	1/15/2009	Financial Swap	3223744	NYMEX NG L1D	Henry Hub			$7.1400		
9/1/2015	1/15/2009	Financial Swap	3223744	NYMEX NG L1D	Henry Hub			$7.1700		
10/1/2015	1/15/2009	Financial Swap	3223744	NYMEX NG L1D	Henry Hub			$7.2500		
8/1/2015	11/7/2012	Financial Swap	3224216	NYMEX NG L1D	Henry Hub			$4.2460		
9/1/2015	11/7/2012	Financial Swap	3224216	NYMEX NG L1D	Henry Hub			$4.2490		
10/1/2015	11/7/2012	Financial Swap	3224216	NYMEX NG L1D	Henry Hub			$4.2660		
8/1/2015	11/9/2012	Financial Swap	3224219	NYMEX NG L1D	Henry Hub			$4.2200		
9/1/2015	11/9/2012	Financial Swap	3224219	NYMEX NG L1D	Henry Hub			$4.2230		
10/1/2015	11/9/2012	Financial Swap	3224219	NYMEX NG L1D	Henry Hub			$4.2600		
8/1/2015	11/13/2012	Financial Swap	3224220	NYMEX NG L1D	Henry Hub			$4.3160		
9/1/2015	11/13/2012	Financial Swap	3224220	NYMEX NG L1D	Henry Hub			$4.3190		
10/1/2015	11/13/2012	Financial Swap	3224220	NYMEX NG L1D	Henry Hub			$4.3560		
8/1/2015	11/15/2012	Financial Swap	3224229	NYMEX NG L1D	Henry Hub			$4.2530		
9/1/2015	11/15/2012	Financial Swap	3224229	NYMEX NG L1D	Henry Hub			$4.2560		
10/1/2015	11/15/2012	Financial Swap	3224229	NYMEX NG L1D	Henry Hub			$4.2930		
8/1/2015	11/19/2012	Financial Swap	3224232	NYMEX NG L1D	Henry Hub			$4.2470		
9/1/2015	11/19/2012	Financial Swap	3224232	NYMEX NG L1D	Henry Hub			$4.2500		
10/1/2015	11/19/2012	Financial Swap	3224232	NYMEX NG L1D	Henry Hub			$4.2870		
8/1/2015	11/27/2012	Financial Swap	3224245	NYMEX NG L1D	Henry Hub			$4.3170		
9/1/2015	11/27/2012	Financial Swap	3224245	NYMEX NG L1D	Henry Hub			$4.3200		
10/1/2015	11/27/2012	Financial Swap	3224245	NYMEX NG L1D	Henry Hub			$4.3570		
8/1/2015	11/28/2012	Financial Swap	3224252	IFERC	Columbia Gulf			$4.2110		
9/1/2015	11/28/2012	Financial Swap	3224252	IFERC	Columbia Gulf			$4.2140		
10/1/2015	11/28/2012	Financial Swap	3224252	IFERC	Columbia Gulf			$4.2510		
8/1/2015	12/10/2012	Financial Swap	3224276	IFERC	Columbia Gulf			$4.0850		
9/1/2015	12/10/2012	Financial Swap	3224276	IFERC	Columbia Gulf			$4.0880		
10/1/2015	12/10/2012	Financial Swap	3224276	IFERC	Columbia Gulf			$4.1240		

REDACTED

Delivery Month	Trade Date	Instrument	Trade Number	Market	Location	Volume MMBtu	Trade Price ($/MMBtu)	Market Price on Trade Date	Percent Difference from Trade Price	
8/1/2015	12/27/2012	Financial Swap	3224280	IFERC	Columbia Gulf			$4.1240		
9/1/2015	12/27/2012	Financial Swap	3224280	IFERC	Columbia Gulf			$4.1270		
10/1/2015	12/27/2012	Financial Swap	3224280	IFERC	Columbia Gulf			$4.1620		
8/1/2015	1/23/2013	Financial Swap	3224337	IFERC	Columbia Gulf			$4.2190		
9/1/2015	1/23/2013	Financial Swap	3224337	IFERC	Columbia Gulf			$4.2220		
10/1/2015	1/23/2013	Financial Swap	3224337	IFERC	Columbia Gulf			$4.2560		
8/1/2015	1/24/2013	Financial Swap	3224381	IFERC	Columbia Gulf			$4.1790		
9/1/2015	1/24/2013	Financial Swap	3224381	IFERC	Columbia Gulf			$4.1820		
10/1/2015	1/24/2013	Financial Swap	3224381	IFERC	Columbia Gulf			$4.2160		
8/1/2015	2/6/2013	Financial Swap	3224384	IFERC	Columbia Gulf			$4.1640		
9/1/2015	2/6/2013	Financial Swap	3224384	IFERC	Columbia Gulf			$4.1670		
10/1/2015	2/6/2013	Financial Swap	3224384	IFERC	Columbia Gulf			$4.2010		
8/1/2015	2/8/2013	Financial Swap	3224508	IFERC	Columbia Gulf			$4.1200		
9/1/2015	2/8/2013	Financial Swap	3224508	IFERC	Columbia Gulf			$4.1230		
10/1/2015	2/8/2013	Financial Swap	3224508	IFERC	Columbia Gulf			$4.1570		
8/1/2015	2/13/2013	Financial Swap	3224509	IFERC	Columbia Gulf			$4.1610		
9/1/2015	2/13/2013	Financial Swap	3224509	IFERC	Columbia Gulf			$4.1640		
10/1/2015	2/13/2013	Financial Swap	3224509	IFERC	Columbia Gulf			$4.1980		
8/1/2015	3/5/2013	Financial Swap	3224604	IFERC	Columbia Gulf			$4.1890		
9/1/2015	3/5/2013	Financial Swap	3224604	IFERC	Columbia Gulf			$4.1930		
10/1/2015	3/5/2013	Financial Swap	3224604	IFERC	Columbia Gulf			$4.2270		
8/1/2015	3/18/2013	Financial Swap	3224618	IFERC	Columbia Gulf			$4.2010		
9/1/2015	3/18/2013	Financial Swap	3224618	IFERC	Columbia Gulf			$4.2040		
10/1/2015	3/18/2013	Financial Swap	3224618	IFERC	Columbia Gulf			$4.2360		
8/1/2015	3/22/2013	Financial Swap	3224620	IFERC	Columbia Gulf			$4.1820		
9/1/2015	3/22/2013	Financial Swap	3224620	IFERC	Columbia Gulf			$4.1850		
10/1/2015	3/22/2013	Financial Swap	3224620	IFERC	Columbia Gulf			$4.2190		
8/1/2015	3/26/2013	Financial Swap	3224621	IFERC	Columbia Gulf			$4.2030		
9/1/2015	3/26/2013	Financial Swap	3224621	IFERC	Columbia Gulf			$4.2060		
10/1/2015	3/26/2013	Financial Swap	3224621	IFERC	Columbia Gulf			$4.2400		
8/1/2015	4/3/2013	Financial Swap	3224640	IFERC	Columbia Gulf			$4.1870		
9/1/2015	4/3/2013	Financial Swap	3224640	IFERC	Columbia Gulf			$4.1900		
10/1/2015	4/3/2013	Financial Swap	3224640	IFERC	Columbia Gulf			$4.2230		
8/1/2015	4/9/2013	Financial Swap	3224679	IFERC	Columbia Gulf			$4.1180		
9/1/2015	4/9/2013	Financial Swap	3224679	IFERC	Columbia Gulf			$4.1210		
10/1/2015	4/9/2013	Financial Swap	3224679	IFERC	Columbia Gulf			$4.1540		
8/1/2015	4/16/2013	Financial Swap	3224681	IFERC	Columbia Gulf			$4.2060		
9/1/2015	4/16/2013	Financial Swap	3224681	IFERC	Columbia Gulf			$4.2090		
10/1/2015	4/16/2013	Financial Swap	3224681	IFERC	Columbia Gulf			$4.2420		
8/1/2015	4/24/2013	Financial Swap	3224682	IFERC	Columbia Gulf			$4.2110		
9/1/2015	4/24/2013	Financial Swap	3224682	IFERC	Columbia Gulf			$4.2140		
10/1/2015	4/24/2013	Financial Swap	3224682	IFERC	Columbia Gulf			$4.2450		
8/1/2015	4/26/2013	Financial Swap	3224683	IFERC	Columbia Gulf			$4.1890		
9/1/2015	4/26/2013	Financial Swap	3224683	IFERC	Columbia Gulf			$4.1910		
10/1/2015	4/26/2013	Financial Swap	3224683	IFERC	Columbia Gulf			$4.2200		
8/1/2015	5/2/2013	Financial Swap	3224684	IFERC	Columbia Gulf			$4.1330		
9/1/2015	5/2/2013	Financial Swap	3224684	IFERC	Columbia Gulf			$4.1350		
10/1/2015	5/2/2013	Financial Swap	3224684	IFERC	Columbia Gulf			$4.1610		
8/1/2015	5/7/2013	Financial Swap	3224693	IFERC	Columbia Gulf			$4.1590		
9/1/2015	5/7/2013	Financial Swap	3224693	IFERC	Columbia Gulf			$4.1610		
10/1/2015	5/7/2013	Financial Swap	3224693	IFERC	Columbia Gulf			$4.1860		
8/1/2015	5/14/2013	Financial Swap	3224697	IFERC	Columbia Gulf			$4.1680		
9/1/2015	5/14/2013	Financial Swap	3224697	IFERC	Columbia Gulf			$4.1690		
10/1/2015	5/14/2013	Financial Swap	3224697	IFERC	Columbia Gulf			$4.1920		
8/1/2015	5/29/2013	Financial Swap	3224807	IFERC	Columbia Gulf			$4.2970		
9/1/2015	5/29/2013	Financial Swap	3224807	IFERC	Columbia Gulf			$4.3000		
10/1/2015	5/29/2013	Financial Swap	3224807	IFERC	Columbia Gulf			$4.3220		
8/1/2015	6/6/2013	Financial Swap	3224813	IFERC	Columbia Gulf			$4.1390		
9/1/2015	6/6/2013	Financial Swap	3224813	IFERC	Columbia Gulf			$4.1410		
10/1/2015	6/6/2013	Financial Swap	3224813	IFERC	Columbia Gulf			$4.1650		
8/1/2015	6/10/2013	Financial Swap	3224815	IFERC	Transco Zone 4			$4.1986		
9/1/2015	6/10/2013	Financial Swap	3224815	IFERC	Transco Zone 4			$4.2006		
10/1/2015	6/10/2013	Financial Swap	3224815	IFERC	Transco Zone 4			$4.2236		
8/1/2015	6/12/2013	Financial Swap	3224817	IFERC	Transco Zone 4			$4.1456		
9/1/2015	6/12/2013	Financial Swap	3224817	IFERC	Transco Zone 4			$4.1446		
10/1/2015	6/12/2013	Financial Swap	3224817	IFERC	Transco Zone 4			$4.1676		
8/1/2015	6/20/2013	Financial Swap	3224818	IFERC	Transco Zone 4			$4.1903		
9/1/2015	6/20/2013	Financial Swap	3224818	IFERC	Transco Zone 4			$4.1893		
10/1/2015	6/20/2013	Financial Swap	3224818	IFERC	Transco Zone 4			$4.2123		
8/1/2015	6/26/2013	Financial Swap	3224826	IFERC	Transco Zone 4			$4.1953		
9/1/2015	6/26/2013	Financial Swap	3224826	IFERC	Transco Zone 4			$4.1943		
10/1/2015	6/26/2013	Financial Swap	3224826	IFERC	Transco Zone 4			$4.2173		
8/1/2015	6/28/2013	Financial Swap	3224914	IFERC	Transco Zone 4			$4.1273		
9/1/2015	6/28/2013	Financial Swap	3224914	IFERC	Transco Zone 4			$4.1263		
10/1/2015	6/28/2013	Financial Swap	3224914	IFERC	Transco Zone 4			$4.1503		
8/1/2015	7/11/2013	Financial Swap	3224915	IFERC	Transco Zone 4			$4.1588		
9/1/2015	7/11/2013	Financial Swap	3224915	IFERC	Transco Zone 4			$4.1568		
10/1/2015	7/11/2013	Financial Swap	3224915	IFERC	Transco Zone 4			$4.1788		
8/1/2015	7/18/2013	Financial Swap	3224916	IFERC	Transco Zone 4			$4.2078		
9/1/2015	7/18/2013	Financial Swap	3224916	IFERC	Transco Zone 4			$4.2078		
10/1/2015	7/18/2013	Financial Swap	3224916	IFERC	Transco Zone 4			$4.2288		
8/1/2015	7/25/2013	Financial Swap	3224919	IFERC	Transco Zone 4			$4.1368		
9/1/2015	7/25/2013	Financial Swap	3224919	IFERC	Transco Zone 4			$4.1358		
10/1/2015	7/25/2013	Financial Swap	3224919	IFERC	Transco Zone 4			$4.1548		
8/1/2015	7/29/2013	Financial Swap	3224921	IFERC	Transco Zone 4			$4.0678		
9/1/2015	7/29/2013	Financial Swap	3224921	IFERC	Transco Zone 4			$4.0668		
10/1/2015	7/29/2013	Financial Swap	3224921	IFERC	Transco Zone 4			$4.0858		
8/1/2015	7/30/2013	Financial Swap	3224923	IFERC	Transco Zone 4			$4.0528		
9/1/2015	7/30/2013	Financial Swap	3224923	IFERC	Transco Zone 4			$4.0518		
10/1/2015	7/30/2013	Financial Swap	3224923	IFERC	Transco Zone 4			$4.0708		
8/1/2015	8/1/2013	Financial Swap	3224925	IFERC	Transco Zone 4			$4.0498		
9/1/2015	8/1/2013	Financial Swap	3224925	IFERC	Transco Zone 4			$4.0488		
10/1/2015	8/1/2013	Financial Swap	3224925	IFERC	Transco Zone 4			$4.0678		
11/1/2015	8/5/2013	Financial Swap	3224926	IFERC	Columbia Gulf			$4.0350		
12/1/2015	8/5/2013	Financial Swap	3224926	IFERC	Columbia Gulf			$4.2070		
8/1/2015	8/5/2013	Financial Swap	3224927	IFERC	Transco Zone 4			$4.0158		
9/1/2015	8/5/2013	Financial Swap	3224927	IFERC	Transco Zone 4			$4.0158		
10/1/2015	8/5/2013	Financial Swap	3224927	IFERC	Transco Zone 4			$4.0358		
11/1/2015	8/6/2013	Financial Swap	3224928	IFERC	Columbia Gulf			$4.0160		
12/1/2015	8/6/2013	Financial Swap	3224928	IFERC	Columbia Gulf			$4.1890		
11/1/2015	8/7/2013	Financial Swap	3224929	IFERC	Columbia Gulf			$3.9820		
12/1/2015	8/7/2013	Financial Swap	3224929	IFERC	Columbia Gulf			$4.1570		
11/1/2015	8/9/2013	Financial Swap	3225039	IFERC	Columbia Gulf			$3.9710		
12/1/2015	8/9/2013	Financial Swap	3225039	IFERC	Columbia Gulf			$4.1430		3.2% vg for the Strip
11/1/2015	8/12/2013	Financial Swap	3225040	IFERC	Columbia Gulf			$4.0020		
12/1/2015	8/12/2013	Financial Swap	3225040	IFERC	Columbia Gulf			$4.1720		
11/1/2015	8/14/2013	Financial Swap	3225041	IFERC	Columbia Gulf			$4.0270		

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Delivery Month	Trade Date	Instrument	Trade Number	Market	Location	Volume MMBtu	Trade Price ($/MMBtu)	Market Price on Trade Date	Percent Difference from Trade Price	
12/1/2015	8/14/2013	Financial Swap	3225041	IFERC	Columbia Gulf			$4.1950		
11/1/2015	8/20/2013	Financial Swap	3225042	IFERC	Columbia Gulf			$4.1050		
12/1/2015	8/20/2013	Financial Swap	3225042	IFERC	Columbia Gulf			$4.2770		
11/1/2015	8/23/2013	Financial Swap	3225043	IFERC	Columbia Gulf			$4.1110		
12/1/2015	8/23/2013	Financial Swap	3225043	IFERC	Columbia Gulf			$4.2810		
8/1/2015	8/23/2013	Financial Swap	3225044	IFERC	Transco Zone 4			$4.0900		
9/1/2015	8/23/2013	Financial Swap	3225044	IFERC	Transco Zone 4			$4.0900		
10/1/2015	8/23/2013	Financial Swap	3225044	IFERC	Transco Zone 4			$4.1090		
11/1/2015	8/27/2013	Financial Swap	3225046	IFERC	Columbia Gulf			$4.1200		
12/1/2015	8/27/2013	Financial Swap	3225046	IFERC	Columbia Gulf			$4.2900		
11/1/2015	8/29/2013	Financial Swap	3225047	IFERC	Columbia Gulf			$4.1310		
12/1/2015	8/29/2013	Financial Swap	3225047	IFERC	Columbia Gulf			$4.3010		
8/1/2015	8/29/2013	Financial Swap	3225050	IFERC	Columbia Gulf			$4.0270		
9/1/2015	8/29/2013	Financial Swap	3225050	IFERC	Columbia Gulf			$4.0270		
10/1/2015	8/29/2013	Financial Swap	3225050	IFERC	Columbia Gulf			$4.0460		
11/1/2015	9/9/2013	Financial Swap	3225056	IFERC	Columbia Gulf			$4.0940		
12/1/2015	9/9/2013	Financial Swap	3225056	IFERC	Columbia Gulf			$4.2640		
8/1/2015	9/9/2013	Financial Swap	3225057	IFERC	Columbia Gulf			$3.9900		
9/1/2015	9/9/2013	Financial Swap	3225057	IFERC	Columbia Gulf			$3.9910		
10/1/2015	9/9/2013	Financial Swap	3225057	IFERC	Columbia Gulf			$4.0100		
11/1/2015	9/10/2013	Financial Swap	3225060	IFERC	Columbia Gulf			$4.0980		
12/1/2015	9/10/2013	Financial Swap	3225060	IFERC	Columbia Gulf			$4.2660		
11/1/2015	9/12/2013	Financial Swap	3225068	IFERC	Columbia Gulf			$4.0880		
12/1/2015	9/12/2013	Financial Swap	3225068	IFERC	Columbia Gulf			$4.2530		
11/1/2015	9/13/2013	Financial Swap	3225069	IFERC	Columbia Gulf			$4.1210		
12/1/2015	9/13/2013	Financial Swap	3225069	IFERC	Columbia Gulf			$4.2860		
11/1/2015	9/25/2013	Financial Swap	3225071	IFERC	Columbia Gulf			$4.0430		
12/1/2015	9/25/2013	Financial Swap	3225071	IFERC	Columbia Gulf			$4.2070		
11/1/2015	9/27/2013	Financial Swap	3225088	IFERC	Columbia Gulf			$4.1020		
12/1/2015	9/27/2013	Financial Swap	3225088	IFERC	Columbia Gulf			$4.2650		
11/1/2015	10/3/2013	Financial Swap	3225107	IFERC	Columbia Gulf			$4.0190		
12/1/2015	10/3/2013	Financial Swap	3225107	IFERC	Columbia Gulf			$4.1830		
11/1/2015	10/8/2013	Financial Swap	3225120	IFERC	Columbia Gulf			$4.1380		
12/1/2015	10/8/2013	Financial Swap	3225120	IFERC	Columbia Gulf			$4.3010		
11/1/2015	10/15/2013	Financial Swap	3225202	IFERC	Columbia Gulf			$4.1500		
12/1/2015	10/15/2013	Financial Swap	3225202	IFERC	Columbia Gulf			$4.3080		
11/1/2015	10/21/2013	Financial Swap	3225203	IFERC	Columbia Gulf			$4.0940		
12/1/2015	10/21/2013	Financial Swap	3225203	IFERC	Columbia Gulf			$4.2480		
8/1/2015	11/1/2013	Financial Swap	3225285	IFERC	Columbia Gulf			$3.7740		
9/1/2015	11/1/2013	Financial Swap	3225285	IFERC	Columbia Gulf			$3.7730		
10/1/2015	11/1/2013	Financial Swap	3225285	IFERC	Columbia Gulf			$3.7960		
11/1/2015	11/4/2013	Financial Swap	3225285	IFERC	Columbia Gulf			$3.8470		
12/1/2015	11/4/2013	Financial Swap	3225285	IFERC	Columbia Gulf			$4.0010		
11/1/2015	1/22/2014	Financial Swap	3226328	IFERC	Columbia Gulf			$4.0300		
12/1/2015	1/22/2014	Financial Swap	3226328	IFERC	Columbia Gulf			$4.1470		
11/1/2015	1/24/2014	Financial Swap	3226334	IFERC	Columbia Gulf			$4.0190		
12/1/2015	1/24/2014	Financial Swap	3226334	IFERC	Columbia Gulf			$4.1300		
11/1/2015	1/27/2014	Financial Swap	3226373	IFERC	Columbia Gulf			$3.9850		
12/1/2015	1/27/2014	Financial Swap	3226373	IFERC	Columbia Gulf			$4.1080		
11/1/2015	2/5/2014	Financial Swap	3226378	IFERC	Transco Zone 4			$4.0690		
12/1/2015	2/5/2014	Financial Swap	3226378	IFERC	Transco Zone 4			$4.2270		
11/1/2015	2/7/2014	Financial Swap	3226447	IFERC	Transco Zone 4			$4.0810		
12/1/2015	2/7/2014	Financial Swap	3226447	IFERC	Transco Zone 4			$4.2390		
11/1/2015	2/28/2014	Financial Swap	3226554	IFERC	Transco Zone 4			$4.0470		3.1%
12/1/2015	2/28/2014	Financial Swap	3226554	IFERC	Transco Zone 4			$4.2310		vg for the Strip
8/1/2015	2/27/2014	Financial Swap	3226557	IFERC	Transco Zone 4			$3.9910		
9/1/2015	2/27/2014	Financial Swap	3226557	IFERC	Transco Zone 4			$3.9730		
10/1/2015	2/27/2014	Financial Swap	3226557	IFERC	Transco Zone 4			$3.9940		
11/1/2015	3/12/2014	Financial Swap	3226563	IFERC	Transco Zone 4			$4.1340		
12/1/2015	3/12/2014	Financial Swap	3226563	IFERC	Transco Zone 4			$4.3040		
11/1/2015	3/18/2014	Financial Swap	3226566	IFERC	Transco Zone 4			$4.1210		
12/1/2015	3/18/2014	Financial Swap	3226566	IFERC	Transco Zone 4			$4.2810		
11/1/2015	3/25/2014	Financial Swap	3226569	IFERC	Transco Zone 4			$4.1490		
12/1/2015	3/25/2014	Financial Swap	3226569	IFERC	Transco Zone 4			$4.3030		
11/1/2015	4/14/2014	Financial Swap	3226754	IFERC	Transco Zone 4			$4.2280		
12/1/2015	4/14/2014	Financial Swap	3226754	IFERC	Transco Zone 4			$4.3610		
11/1/2015	5/21/2014	Financial Swap	3226790	IFERC	Transco Zone 4			$4.1830		
12/1/2015	5/21/2014	Financial Swap	3226790	IFERC	Transco Zone 4			$4.3300		
11/1/2015	5/27/2014	Financial Swap	3226796	IFERC	Henry Hub			$4.1845		
12/1/2015	5/27/2014	Financial Swap	3226796	IFERC	Henry Hub			$4.3325		
11/1/2015	6/18/2014	Financial Swap	3226801	IFERC	Transco Zone 4			$4.3080		
12/1/2015	6/18/2014	Financial Swap	3226801	IFERC	Transco Zone 4			$4.4450		
11/1/2015	6/23/2014	Financial Swap	3226803	IFERC	Transco Zone 4			$4.2170		
12/1/2015	6/23/2014	Financial Swap	3226803	IFERC	Transco Zone 4			$4.3590		
8/1/2015	6/25/2014	Financial Swap	3228840	IFERC	Henry Hub			$4.1595		
9/1/2015	6/25/2014	Financial Swap	3228840	IFERC	Henry Hub			$4.1445		
11/1/2015	7/25/2014	Financial Swap	3238365	IFERC	Henry Hub			$3.8715		3.1%
12/1/2015	7/25/2014	Financial Swap	3238365	IFERC	Henry Hub			$4.0465		vg for the Strip
11/1/2015	7/31/2014	Financial Swap	3240195	IFERC	Henry Hub			$3.9065		3.2%
12/1/2015	7/31/2014	Financial Swap	3240195	IFERC	Henry Hub			$4.0765		vg for the Strip
11/1/2015	8/13/2014	Financial Swap	3243801	IFERC	Henry Hub			$3.9515		
12/1/2015	8/13/2014	Financial Swap	3243801	IFERC	Henry Hub			$4.1045		
11/1/2015	9/4/2014	Financial Swap	3251815	IFERC	Transco Zone 4			$3.9985		
12/1/2015	9/4/2014	Financial Swap	3251815	IFERC	Transco Zone 4			$4.1475		
11/1/2015	9/22/2014	Financial Swap	3257541	IFERC	Columbia Gulf			$3.8830		
12/1/2015	9/22/2014	Financial Swap	3257541	IFERC	Columbia Gulf			$4.0300		
8/1/2015	10/23/2014	Financial Swap	3267250	IFERC	Columbia Gulf			$3.5265		
9/1/2015	10/23/2014	Financial Swap	3267250	IFERC	Columbia Gulf			$3.5195		
10/1/2015	10/23/2014	Financial Swap	3267250	IFERC	Columbia Gulf			$3.5485		
11/1/2015	10/30/2014	Financial Swap	3269357	IFERC	Columbia Gulf			$3.7250		
12/1/2015	10/30/2014	Financial Swap	3269357	IFERC	Columbia Gulf			$3.8800		
8/1/2015	12/15/2014	Financial Swap	3283784	IFERC	Transco Zone 4			$3.5265		
9/1/2015	12/15/2014	Financial Swap	3283784	IFERC	Transco Zone 4			$3.5095		
10/1/2015	12/15/2014	Financial Swap	3283784	IFERC	Transco Zone 4			$3.5390		
8/1/2015	12/17/2014	Financial Swap	3284453	IFERC	Transco Zone 4			$3.4945		
9/1/2015	12/17/2014	Financial Swap	3284453	IFERC	Transco Zone 4			$3.4755		
10/1/2015	12/17/2014	Financial Swap	3284453	IFERC	Transco Zone 4			$3.5060		
8/1/2015	12/23/2014	Financial Swap	3286344	IFERC	Transco Zone 4			$3.2095		
9/1/2015	12/23/2014	Financial Swap	3286344	IFERC	Transco Zone 4			$3.1965		
10/1/2015	12/23/2014	Financial Swap	3286344	IFERC	Transco Zone 4			$3.2250		
11/1/2015	12/23/2014	Financial Swap	3286345	NYMEX NG L1D	Henry Hub			$3.3540		3.0%
12/1/2015	12/23/2014	Financial Swap	3286345	NYMEX NG L1D	Henry Hub			$3.5500		vg for the Strip
11/1/2015	1/20/2015	Financial Swap	3294865	NYMEX NG L1D	Henry Hub			$3.0550		4.3%
12/1/2015	1/20/2015	Financial Swap	3294865	NYMEX NG L1D	Henry Hub			$3.2420		vg for the Strip
8/1/2015	1/20/2015	Financial Swap	3294866	IFERC	Transco Zone 4			$2.8900		
9/1/2015	1/20/2015	Financial Swap	3294866	IFERC	Transco Zone 4			$2.8710		
10/1/2015	1/20/2015	Financial Swap	3294866	IFERC	Transco Zone 4			$2.9055		

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Delivery Month	Trade Date	Instrument	Trade Number	Market	Location	Volume MMBtu	Trade Price ($/MMBtu)	Market Price on Trade Date	Percent Difference from Trade Price		
11/1/2015	1/29/2015	Financial Swap	3297902	IFERC	Transco Zone 4			$3.0025		3.1%	
12/1/2015	1/29/2015	Financial Swap	3297902	IFERC	Transco Zone 4			$3.1925		Avg for the Strip	
8/1/2015	1/29/2015	Financial Swap	3297904	NYMEX NG L1D	Henry Hub			$2.8590			
9/1/2015	1/29/2015	Financial Swap	3297904	NYMEX NG L1D	Henry Hub			$2.8460			
11/1/2015	2/9/2015	Financial Swap	3301240	IFERC	Transco Zone 4			$2.9450		3.8%	
12/1/2015	2/9/2015	Financial Swap	3301240	IFERC	Transco Zone 4			$3.1390		Avg for the Strip	
8/1/2015	2/23/2015	Financial Swap	3306466	NYMEX NG L1D	Henry Hub			$3.0190			
9/1/2015	2/23/2015	Financial Swap	3306466	NYMEX NG L1D	Henry Hub			$3.0080			
10/1/2015	2/23/2015	Financial Swap	3306466	NYMEX NG L1D	Henry Hub			$3.0320			
11/1/2015	2/23/2015	Financial Swap	3306467	NYMEX NG L1D	Henry Hub			$3.1070		3.5%	
12/1/2015	2/23/2015	Financial Swap	3306467	NYMEX NG L1D	Henry Hub			$3.2480		Avg for the Strip	
11/1/2015	2/28/2015	Financial Swap	3307909	NYMEX NG L1D	Henry Hub			$2.9730		4.2%	
12/1/2015	2/28/2015	Financial Swap	3307909	NYMEX NG L1D	Henry Hub			$3.1370		Avg for the Strip	
8/1/2015	2/28/2015	Financial Swap	3307910	NYMEX NG L1D	Henry Hub			$2.8500			
9/1/2015	2/28/2015	Financial Swap	3307910	NYMEX NG L1D	Henry Hub			$2.8400			
11/1/2015	3/4/2015	Financial Swap	3310403	IFERC	Transco Zone 4			$3.0310		3.5%	
12/1/2015	3/4/2015	Financial Swap	3310403	IFERC	Transco Zone 4			$3.1890		Avg for the Strip	
11/1/2015	3/9/2015	Financial Swap	3312109	IFERC	Transco Zone 4			$2.9530		5.0%	See Note 1 Below, Item #1
12/1/2015	3/9/2015	Financial Swap	3312109	IFERC	Transco Zone 4			$3.1200		Avg for the Strip	Avg for entire strip was 1.3%
11/1/2015	3/25/2015	Financial Swap	3317825	IFERC	Transco Zone 4			$2.9950		3.5%	
12/1/2015	3/25/2015	Financial Swap	3317825	IFERC	Transco Zone 4			$3.1490		Avg for the Strip	
8/1/2015	4/9/2015	Financial Swap	3321455	NYMEX NG L1D	Henry Hub			$2.8670			
9/1/2015	4/9/2015	Financial Swap	3321455	NYMEX NG L1D	Henry Hub			$2.8750			
11/1/2015	4/9/2015	Financial Swap	3321456	NYMEX NG L1D	Henry Hub			$2.8170		3.7%	
12/1/2015	4/9/2015	Financial Swap	3321456	NYMEX NG L1D	Henry Hub			$2.9930		Avg for the Strip	
8/1/2015	4/16/2015	Financial Swap	3322457	NYMEX NG L1D	Henry Hub			$2.8010		5.8%	See Note 1 Below, Item #2
9/1/2015	4/16/2015	Financial Swap	3322457	NYMEX NG L1D	Henry Hub			$2.8030		Avg for the Strip	Avg for entire strip was 4.3%
10/1/2015	4/16/2015	Financial Swap	3322457	NYMEX NG L1D	Henry Hub			$2.8310			
11/1/2015	4/16/2015	Financial Swap	3322458	NYMEX NG L1D	Henry Hub			$2.9220			
12/1/2015	4/16/2015	Financial Swap	3322458	NYMEX NG L1D	Henry Hub			$3.0960			
8/1/2015	4/20/2015	Financial Swap	3323023	IFERC	Transco Zone 4			$2.6670			
9/1/2015	4/20/2015	Financial Swap	3323023	IFERC	Transco Zone 4			$2.6740			
10/1/2015	4/20/2015	Financial Swap	3323023	IFERC	Transco Zone 4			$2.7070			
11/1/2015	4/20/2015	Financial Swap	3323024	IFERC	Transco Zone 4			$2.8160		3.8%	
12/1/2015	4/20/2015	Financial Swap	3323024	IFERC	Transco Zone 4			$2.9930		Avg for the Strip	
8/1/2015	4/27/2015	Financial Swap	3324163	IFERC	Transco Zone 4			$2.5695			
9/1/2015	4/27/2015	Financial Swap	3324163	IFERC	Transco Zone 4			$2.5920			
10/1/2015	4/27/2015	Financial Swap	3324163	IFERC	Transco Zone 4			$2.6390			
11/1/2015	4/27/2015	Financial Swap	3324164	IFERC	Transco Zone 4			$2.7940		3.5%	
12/1/2015	4/27/2015	Financial Swap	3324164	IFERC	Transco Zone 4			$2.9790		Avg for the Strip	
8/1/2015	5/20/2015	Financial Swap	3328730	IFERC	Columbia Gulf			$2.9020			
8/1/2015	5/29/2015	Financial Swap	3330748	IFERC	Columbia Gulf			$2.5825			
9/1/2015	5/29/2015	Financial Swap	3330748	IFERC	Columbia Gulf			$2.5875			
10/1/2015	5/29/2015	Financial Swap	3330748	IFERC	Columbia Gulf			$2.8215			
11/1/2015	5/29/2015	Financial Swap	3330749	IFERC	Columbia Gulf			$2.7300		4.4%	
12/1/2015	5/29/2015	Financial Swap	3330749	IFERC	Columbia Gulf			$2.9245		Avg for the Strip	
8/1/2015	6/2/2015	Financial Swap	3331414	IFERC	Columbia Gulf			$2.6350			
9/1/2015	6/2/2015	Financial Swap	3331414	IFERC	Columbia Gulf			$2.6485			
10/1/2015	6/2/2015	Financial Swap	3331414	IFERC	Columbia Gulf			$2.6780			
11/1/2015	10/1/2015	Financial Swap	3356803	IFERC	Transco Zone 4			$2.4355		6.7%	See Note 1 Below, Item #3
12/1/2015	10/1/2015	Financial Swap	3356803	IFERC	Transco Zone 4			$2.6460		Avg for the Strip	Avg for entire strip was 1.5%

* Percentage difference from trade price - Negative identifies when a trade price is above the closing market price for the respective day based on the simplified comparison.
* Percentage difference from trade price - Positive identifies when a trade price is below the closing market price for the respective day based on the simplified comparison.

Note 1
These trades below were strip trades for multiple months. Due to the test period of the request being different than the actual months of the strip deals executed, this causes the appearance of trades being more than 5% different from the market price for the respective day based on the simplified comparison. Below, the entire strips have been put together to show the trades were not 5% different than market when in complete form. All trades are executed at the prevailing market price at the time of the trade.

Item #1

11/1/2015	3/9/2015	Financial Swap	3312109	IFERC	Transco Zone 4			$2.9530		1.3%
12/1/2015	3/9/2015	Financial Swap	3312109	IFERC	Transco Zone 4			$3.1200		Avg for the Strip
1/1/2016	3/9/2015	Financial Swap	3312109	IFERC	Transco Zone 4			$3.2565		
2/1/2016	3/9/2015	Financial Swap	3312109	IFERC	Transco Zone 4			$3.2475		
3/1/2016	3/9/2015	Financial Swap	3312109	IFERC	Transco Zone 4			$3.2055		

Item #2

5/1/2015	4/16/2015	Financial Swap	3322457	NYMEX NG L1D	Henry Hub			$2.6840		4.3%
6/1/2015	4/16/2015	Financial Swap	3322457	NYMEX NG L1D	Henry Hub			$2.7260		Avg for the Strip
7/1/2015	4/16/2015	Financial Swap	3322457	NYMEX NG L1D	Henry Hub			$2.7840		
8/1/2015	4/16/2015	Financial Swap	3322457	NYMEX NG L1D	Henry Hub			$2.8010		
9/1/2015	4/16/2015	Financial Swap	3322457	NYMEX NG L1D	Henry Hub			$2.8030		
10/1/2015	4/16/2015	Financial Swap	3322457	NYMEX NG L1D	Henry Hub			$2.8310		

Item #3

11/1/2015	10/1/2015	Financial Swap	3356803	IFERC	Transco Zone 4			$2.4355		1.5%
12/1/2015	10/1/2015	Financial Swap	3356803	IFERC	Transco Zone 4			$2.6460		Avg for the Strip
1/1/2016	10/1/2015	Financial Swap	3356803	IFERC	Transco Zone 4			$2.7880		
2/1/2016	10/1/2015	Financial Swap	3356803	IFERC	Transco Zone 4			$2.7825		
3/1/2016	10/1/2015	Financial Swap	3356803	IFERC	Transco Zone 4			$2.7540		

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2016 January - July Swap Hedges

Delivery Month	Trade Date	Instrument	Trade Number	Market	Location	Volume MMBtu	Trade Price ($/MMBtu)	Market Price on Trade Date	Percent Difference from Trade Price
1/1/2016	8/5/2013	Financial Swap	3224926	IFERC	Columbia Gulf			$4.3010	
2/1/2016	8/5/2013	Financial Swap	3224926	IFERC	Columbia Gulf			$4.2860	
3/1/2016	8/5/2013	Financial Swap	3224926	IFERC	Columbia Gulf			$4.2210	
1/1/2016	8/6/2013	Financial Swap	3224928	IFERC	Columbia Gulf			$4.2860	
2/1/2016	8/6/2013	Financial Swap	3224928	IFERC	Columbia Gulf			$4.2710	
3/1/2016	8/6/2013	Financial Swap	3224928	IFERC	Columbia Gulf			$4.2060	
1/1/2016	8/7/2013	Financial Swap	3224929	IFERC	Columbia Gulf			$4.2500	
2/1/2016	8/7/2013	Financial Swap	3224929	IFERC	Columbia Gulf			$4.2350	
3/1/2016	8/7/2013	Financial Swap	3224929	IFERC	Columbia Gulf			$4.1720	
1/1/2016	8/9/2013	Financial Swap	3225039	IFERC	Columbia Gulf			$4.2350	
2/1/2016	8/9/2013	Financial Swap	3225039	IFERC	Columbia Gulf			$4.2200	
3/1/2016	8/9/2013	Financial Swap	3225039	IFERC	Columbia Gulf			$4.1550	
1/1/2016	8/12/2013	Financial Swap	3225040	IFERC	Columbia Gulf			$4.2670	
2/1/2016	8/12/2013	Financial Swap	3225040	IFERC	Columbia Gulf			$4.2510	
3/1/2016	8/12/2013	Financial Swap	3225040	IFERC	Columbia Gulf			$4.1840	
1/1/2016	8/14/2013	Financial Swap	3225041	IFERC	Columbia Gulf			$4.2810	
2/1/2016	8/14/2013	Financial Swap	3225041	IFERC	Columbia Gulf			$4.2650	
3/1/2016	8/14/2013	Financial Swap	3225041	IFERC	Columbia Gulf			$4.1980	
1/1/2016	8/20/2013	Financial Swap	3225042	IFERC	Columbia Gulf			$4.3570	
2/1/2016	8/20/2013	Financial Swap	3225042	IFERC	Columbia Gulf			$4.3370	
3/1/2016	8/20/2013	Financial Swap	3225042	IFERC	Columbia Gulf			$4.2660	
1/1/2016	8/23/2013	Financial Swap	3225043	IFERC	Columbia Gulf			$4.3620	
2/1/2016	8/23/2013	Financial Swap	3225043	IFERC	Columbia Gulf			$4.3420	
3/1/2016	8/23/2013	Financial Swap	3225043	IFERC	Columbia Gulf			$4.2720	
1/1/2016	8/27/2013	Financial Swap	3225046	IFERC	Columbia Gulf			$4.3710	
2/1/2016	8/27/2013	Financial Swap	3225046	IFERC	Columbia Gulf			$4.3510	
3/1/2016	8/27/2013	Financial Swap	3225046	IFERC	Columbia Gulf			$4.2810	
1/1/2016	8/29/2013	Financial Swap	3225047	IFERC	Columbia Gulf			$4.3840	
2/1/2016	8/29/2013	Financial Swap	3225047	IFERC	Columbia Gulf			$4.3640	
3/1/2016	8/29/2013	Financial Swap	3225047	IFERC	Columbia Gulf			$4.2940	
1/1/2016	9/9/2013	Financial Swap	3225056	IFERC	Columbia Gulf			$4.3460	
2/1/2016	9/9/2013	Financial Swap	3225056	IFERC	Columbia Gulf			$4.3240	
3/1/2016	9/9/2013	Financial Swap	3225056	IFERC	Columbia Gulf			$4.2540	
1/1/2016	9/10/2013	Financial Swap	3225060	IFERC	Columbia Gulf			$4.3410	
2/1/2016	9/10/2013	Financial Swap	3225060	IFERC	Columbia Gulf			$4.3190	
3/1/2016	9/10/2013	Financial Swap	3225060	IFERC	Columbia Gulf			$4.2490	
1/1/2016	9/12/2013	Financial Swap	3225068	IFERC	Columbia Gulf			$4.3270	
2/1/2016	9/12/2013	Financial Swap	3225068	IFERC	Columbia Gulf			$4.3030	
3/1/2016	9/12/2013	Financial Swap	3225068	IFERC	Columbia Gulf			$4.2310	
1/1/2016	9/13/2013	Financial Swap	3225069	IFERC	Columbia Gulf			$4.3610	
2/1/2016	9/13/2013	Financial Swap	3225069	IFERC	Columbia Gulf			$4.3370	
3/1/2016	9/13/2013	Financial Swap	3225069	IFERC	Columbia Gulf			$4.2650	
1/1/2016	9/25/2013	Financial Swap	3225071	IFERC	Columbia Gulf			$4.2810	
2/1/2016	9/25/2013	Financial Swap	3225071	IFERC	Columbia Gulf			$4.2590	
3/1/2016	9/25/2013	Financial Swap	3225071	IFERC	Columbia Gulf			$4.1890	
1/1/2016	9/27/2013	Financial Swap	3225088	IFERC	Columbia Gulf			$4.3340	
2/1/2016	9/27/2013	Financial Swap	3225088	IFERC	Columbia Gulf			$4.3130	
3/1/2016	9/27/2013	Financial Swap	3225088	IFERC	Columbia Gulf			$4.2430	
1/1/2016	10/3/2013	Financial Swap	3225107	IFERC	Columbia Gulf			$4.2520	
2/1/2016	10/3/2013	Financial Swap	3225107	IFERC	Columbia Gulf			$4.2310	
3/1/2016	10/3/2013	Financial Swap	3225107	IFERC	Columbia Gulf			$4.1610	
1/1/2016	10/8/2013	Financial Swap	3225120	IFERC	Columbia Gulf			$4.3690	
2/1/2016	10/8/2013	Financial Swap	3225120	IFERC	Columbia Gulf			$4.3460	
3/1/2016	10/8/2013	Financial Swap	3225120	IFERC	Columbia Gulf			$4.2740	
1/1/2016	10/15/2013	Financial Swap	3225202	IFERC	Columbia Gulf			$4.3660	
2/1/2016	10/15/2013	Financial Swap	3225202	IFERC	Columbia Gulf			$4.3430	
3/1/2016	10/15/2013	Financial Swap	3225202	IFERC	Columbia Gulf			$4.2710	
1/1/2016	10/21/2013	Financial Swap	3225203	IFERC	Columbia Gulf			$4.3070	
2/1/2016	10/21/2013	Financial Swap	3225203	IFERC	Columbia Gulf			$4.2850	
3/1/2016	10/21/2013	Financial Swap	3225203	IFERC	Columbia Gulf			$4.2150	
4/1/2016	11/1/2013	Financial Swap	3225209	IFERC	Columbia Gulf			$3.8110	
5/1/2016	11/1/2013	Financial Swap	3225209	IFERC	Columbia Gulf			$3.8230	
6/1/2016	11/1/2013	Financial Swap	3225209	IFERC	Columbia Gulf			$3.8470	
7/1/2016	11/1/2013	Financial Swap	3225209	IFERC	Columbia Gulf			$3.8780	
4/1/2016	11/4/2013	Financial Swap	3225282	IFERC	Columbia Gulf			$3.7770	
5/1/2016	11/4/2013	Financial Swap	3225282	IFERC	Columbia Gulf			$3.7890	
6/1/2016	11/4/2013	Financial Swap	3225282	IFERC	Columbia Gulf			$3.8130	
7/1/2016	11/4/2013	Financial Swap	3225282	IFERC	Columbia Gulf			$3.8440	
1/1/2016	11/4/2013	Financial Swap	3225285	IFERC	Columbia Gulf			$4.0730	
2/1/2016	11/4/2013	Financial Swap	3225285	IFERC	Columbia Gulf			$4.0570	
3/1/2016	11/4/2013	Financial Swap	3225285	IFERC	Columbia Gulf			$3.9950	
4/1/2016	11/7/2013	Financial Swap	3225287	IFERC	Columbia Gulf			$3.8300	
5/1/2016	11/7/2013	Financial Swap	3225287	IFERC	Columbia Gulf			$3.8420	
6/1/2016	11/7/2013	Financial Swap	3225287	IFERC	Columbia Gulf			$3.8660	
7/1/2016	11/7/2013	Financial Swap	3225287	IFERC	Columbia Gulf			$3.8960	
4/1/2016	11/11/2013	Financial Swap	3225288	IFERC	Columbia Gulf			$3.8510	
5/1/2016	11/11/2013	Financial Swap	3225288	IFERC	Columbia Gulf			$3.8630	
6/1/2016	11/11/2013	Financial Swap	3225288	IFERC	Columbia Gulf			$3.8870	
7/1/2016	11/11/2013	Financial Swap	3225288	IFERC	Columbia Gulf			$3.9150	
4/1/2016	11/18/2013	Financial Swap	3225289	IFERC	Columbia Gulf			$3.8450	
5/1/2016	11/18/2013	Financial Swap	3225289	IFERC	Columbia Gulf			$3.8570	
6/1/2016	11/18/2013	Financial Swap	3225289	IFERC	Columbia Gulf			$3.8820	
7/1/2016	11/18/2013	Financial Swap	3225289	IFERC	Columbia Gulf			$3.9100	
4/1/2016	11/20/2013	Financial Swap	3225290	IFERC	Columbia Gulf			$3.8530	
5/1/2016	11/20/2013	Financial Swap	3225290	IFERC	Columbia Gulf			$3.8650	
6/1/2016	11/20/2013	Financial Swap	3225290	IFERC	Columbia Gulf			$3.8890	
7/1/2016	11/20/2013	Financial Swap	3225290	IFERC	Columbia Gulf			$3.9160	
4/1/2016	11/25/2013	Financial Swap	3225291	IFERC	Columbia Gulf			$3.8860	
5/1/2016	11/25/2013	Financial Swap	3225291	IFERC	Columbia Gulf			$3.8980	
6/1/2016	11/25/2013	Financial Swap	3225291	IFERC	Columbia Gulf			$3.9220	
7/1/2016	11/25/2013	Financial Swap	3225291	IFERC	Columbia Gulf			$3.9490	
4/1/2016	11/26/2013	Financial Swap	3225858	IFERC	Transco Zone 4			$4.0191	
5/1/2016	11/26/2013	Financial Swap	3225858	IFERC	Transco Zone 4			$4.0311	
6/1/2016	11/26/2013	Financial Swap	3225858	IFERC	Transco Zone 4			$4.0551	
7/1/2016	11/26/2013	Financial Swap	3225858	IFERC	Transco Zone 4			$4.0821	

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Delivery Month	Trade Date	Instrument	Trade Number	Market	Location	Volume MMBtu	Trade Price ($/MMBtu)	Market Price on Trade Date	Percent Difference from Trade Price
4/1/2016	12/2/2013	Financial Swap	3225859	IFERC	Transco Zone 4			$4.0701	
5/1/2016	12/2/2013	Financial Swap	3225859	IFERC	Transco Zone 4			$4.0821	
6/1/2016	12/2/2013	Financial Swap	3225859	IFERC	Transco Zone 4			$4.1051	
7/1/2016	12/2/2013	Financial Swap	3225859	IFERC	Transco Zone 4			$4.1311	
4/1/2016	12/5/2013	Financial Swap	3225864	IFERC	Transco Zone 4			$4.1071	
5/1/2016	12/5/2013	Financial Swap	3225864	IFERC	Transco Zone 4			$4.1191	
6/1/2016	12/5/2013	Financial Swap	3225864	IFERC	Transco Zone 4			$4.1421	
7/1/2016	12/5/2013	Financial Swap	3225864	IFERC	Transco Zone 4			$4.1681	
4/1/2016	12/9/2013	Financial Swap	3225874	IFERC	Transco Zone 4			$4.1311	
5/1/2016	12/9/2013	Financial Swap	3225874	IFERC	Transco Zone 4			$4.1421	
6/1/2016	12/9/2013	Financial Swap	3225874	IFERC	Transco Zone 4			$4.1641	
7/1/2016	12/9/2013	Financial Swap	3225874	IFERC	Transco Zone 4			$4.1881	
4/1/2016	12/19/2013	Financial Swap	3226122	IFERC	Transco Zone 4			$4.0083	
5/1/2016	12/19/2013	Financial Swap	3226122	IFERC	Transco Zone 4			$4.0133	
6/1/2016	12/19/2013	Financial Swap	3226122	IFERC	Transco Zone 4			$4.0333	
7/1/2016	12/19/2013	Financial Swap	3226122	IFERC	Transco Zone 4			$4.0583	
4/1/2016	1/10/2014	Financial Swap	3226130	IFERC	Transco Zone 4			$3.9075	
5/1/2016	1/10/2014	Financial Swap	3226130	IFERC	Transco Zone 4			$3.9125	
6/1/2016	1/10/2014	Financial Swap	3226130	IFERC	Transco Zone 4			$3.9305	
7/1/2016	1/10/2014	Financial Swap	3226130	IFERC	Transco Zone 4			$3.9515	
4/1/2016	1/22/2014	Financial Swap	3226321	IFERC	Transco Zone 4			$3.9955	
5/1/2016	1/22/2014	Financial Swap	3226321	IFERC	Transco Zone 4			$3.9975	
6/1/2016	1/22/2014	Financial Swap	3226321	IFERC	Transco Zone 4			$4.0155	
7/1/2016	1/22/2014	Financial Swap	3226321	IFERC	Transco Zone 4			$4.0365	
1/1/2016	1/22/2014	Financial Swap	3226328	IFERC	Columbia Gulf			$4.2410	
2/1/2016	1/22/2014	Financial Swap	3226328	IFERC	Columbia Gulf			$4.2160	
3/1/2016	1/22/2014	Financial Swap	3226328	IFERC	Columbia Gulf			$4.1630	
4/1/2016	1/24/2014	Financial Swap	3226333	IFERC	Transco Zone 4			$3.9795	
5/1/2016	1/24/2014	Financial Swap	3226333	IFERC	Transco Zone 4			$3.9815	
6/1/2016	1/24/2014	Financial Swap	3226333	IFERC	Transco Zone 4			$3.9995	
7/1/2016	1/24/2014	Financial Swap	3226333	IFERC	Transco Zone 4			$4.0205	
1/1/2016	1/24/2014	Financial Swap	3226334	IFERC	Columbia Gulf			$4.2300	
2/1/2016	1/24/2014	Financial Swap	3226334	IFERC	Columbia Gulf			$4.2050	
3/1/2016	1/24/2014	Financial Swap	3226334	IFERC	Columbia Gulf			$4.1520	
4/1/2016	1/27/2014	Financial Swap	3226348	IFERC	Transco Zone 4			$3.9725	
5/1/2016	1/27/2014	Financial Swap	3226348	IFERC	Transco Zone 4			$3.9815	
6/1/2016	1/27/2014	Financial Swap	3226348	IFERC	Transco Zone 4			$4.0055	
7/1/2016	1/27/2014	Financial Swap	3226348	IFERC	Transco Zone 4			$4.0305	
1/1/2016	1/27/2014	Financial Swap	3226373	IFERC	Columbia Gulf			$4.2060	
2/1/2016	1/27/2014	Financial Swap	3226373	IFERC	Columbia Gulf			$4.1820	
3/1/2016	1/27/2014	Financial Swap	3226373	IFERC	Columbia Gulf			$4.1300	
4/1/2016	1/30/2014	Financial Swap	3226375	IFERC	Transco Zone 4			$3.9275	
5/1/2016	1/30/2014	Financial Swap	3226375	IFERC	Transco Zone 4			$3.9355	
6/1/2016	1/30/2014	Financial Swap	3226375	IFERC	Transco Zone 4			$3.9595	
7/1/2016	1/30/2014	Financial Swap	3226375	IFERC	Transco Zone 4			$3.9845	
4/1/2016	2/5/2014	Financial Swap	3226376	IFERC	Transco Zone 4			$3.9435	
5/1/2016	2/5/2014	Financial Swap	3226376	IFERC	Transco Zone 4			$3.9535	
6/1/2016	2/5/2014	Financial Swap	3226376	IFERC	Transco Zone 4			$3.9775	
7/1/2016	2/5/2014	Financial Swap	3226376	IFERC	Transco Zone 4			$4.0045	
1/1/2016	2/5/2014	Financial Swap	3226378	IFERC	Transco Zone 4			$4.3550	
2/1/2016	2/5/2014	Financial Swap	3226378	IFERC	Transco Zone 4			$4.3260	
3/1/2016	2/5/2014	Financial Swap	3226378	IFERC	Transco Zone 4			$4.2710	
4/1/2016	2/6/2014	Financial Swap	3226430	IFERC	Columbia Gulf			$3.8480	
5/1/2016	2/6/2014	Financial Swap	3226430	IFERC	Columbia Gulf			$3.8580	
6/1/2016	2/6/2014	Financial Swap	3226430	IFERC	Columbia Gulf			$3.8820	
7/1/2016	2/6/2014	Financial Swap	3226430	IFERC	Columbia Gulf			$3.9090	
1/1/2016	2/7/2014	Financial Swap	3226447	IFERC	Transco Zone 4			$4.3600	
2/1/2016	2/7/2014	Financial Swap	3226447	IFERC	Transco Zone 4			$4.3400	
3/1/2016	2/7/2014	Financial Swap	3226447	IFERC	Transco Zone 4			$4.2850	
4/1/2016	2/18/2014	Financial Swap	3226497	IFERC	Columbia Gulf			$3.8555	
5/1/2016	2/18/2014	Financial Swap	3226497	IFERC	Columbia Gulf			$3.8655	
6/1/2016	2/18/2014	Financial Swap	3226497	IFERC	Columbia Gulf			$3.8895	
7/1/2016	2/18/2014	Financial Swap	3226497	IFERC	Columbia Gulf			$3.9155	
4/1/2016	2/26/2014	Financial Swap	3226553	IFERC	Columbia Gulf			$3.8610	
5/1/2016	2/26/2014	Financial Swap	3226553	IFERC	Columbia Gulf			$3.8710	
6/1/2016	2/26/2014	Financial Swap	3226553	IFERC	Columbia Gulf			$3.8950	
7/1/2016	2/26/2014	Financial Swap	3226553	IFERC	Columbia Gulf			$3.9210	
1/1/2016	2/26/2014	Financial Swap	3226554	IFERC	Transco Zone 4			$4.3830	
2/1/2016	2/26/2014	Financial Swap	3226554	IFERC	Transco Zone 4			$4.3580	
3/1/2016	2/26/2014	Financial Swap	3226554	IFERC	Transco Zone 4			$4.3010	
4/1/2016	3/11/2014	Financial Swap	3226562	IFERC	Columbia Gulf			$3.9980	
5/1/2016	3/11/2014	Financial Swap	3226562	IFERC	Columbia Gulf			$4.0050	
6/1/2016	3/11/2014	Financial Swap	3226562	IFERC	Columbia Gulf			$4.0250	
7/1/2016	3/11/2014	Financial Swap	3226562	IFERC	Columbia Gulf			$4.0470	
4/1/2016	3/12/2014	Financial Swap	3226560	IFERC	Columbia Gulf			$3.9800	
5/1/2016	3/12/2014	Financial Swap	3226560	IFERC	Columbia Gulf			$3.9870	
6/1/2016	3/12/2014	Financial Swap	3226560	IFERC	Columbia Gulf			$4.0070	
7/1/2016	3/12/2014	Financial Swap	3226560	IFERC	Columbia Gulf			$4.0290	
1/1/2016	3/12/2014	Financial Swap	3226563	IFERC	Transco Zone 4			$4.4480	
2/1/2016	3/12/2014	Financial Swap	3226563	IFERC	Transco Zone 4			$4.4210	
3/1/2016	3/12/2014	Financial Swap	3226563	IFERC	Transco Zone 4			$4.3600	
4/1/2016	3/14/2014	Financial Swap	3226564	IFERC	Columbia Gulf			$3.9970	
5/1/2016	3/14/2014	Financial Swap	3226564	IFERC	Columbia Gulf			$4.0030	
6/1/2016	3/14/2014	Financial Swap	3226564	IFERC	Columbia Gulf			$4.0220	
7/1/2016	3/14/2014	Financial Swap	3226564	IFERC	Columbia Gulf			$4.0430	
4/1/2016	3/18/2014	Financial Swap	3226565	IFERC	Henry Hub			$4.0405	
5/1/2016	3/18/2014	Financial Swap	3226565	IFERC	Henry Hub			$4.0465	
6/1/2016	3/18/2014	Financial Swap	3226565	IFERC	Henry Hub			$4.0655	
7/1/2016	3/18/2014	Financial Swap	3226565	IFERC	Henry Hub			$4.0865	
1/1/2016	3/18/2014	Financial Swap	3226566	IFERC	Transco Zone 4			$4.4130	
2/1/2016	3/18/2014	Financial Swap	3226566	IFERC	Transco Zone 4			$4.3880	
3/1/2016	3/18/2014	Financial Swap	3226566	IFERC	Transco Zone 4			$4.3280	
4/1/2016	3/25/2014	Financial Swap	3226568	IFERC	Henry Hub			$4.0735	
5/1/2016	3/25/2014	Financial Swap	3226568	IFERC	Henry Hub			$4.0795	
6/1/2016	3/25/2014	Financial Swap	3226568	IFERC	Henry Hub			$4.0975	
7/1/2016	3/25/2014	Financial Swap	3226568	IFERC	Henry Hub			$4.1175	
1/1/2016	3/25/2014	Financial Swap	3226569	IFERC	Transco Zone 4			$4.4350	
2/1/2016	3/25/2014	Financial Swap	3226569	IFERC	Transco Zone 4			$4.4080	
3/1/2016	3/25/2014	Financial Swap	3226569	IFERC	Transco Zone 4			$4.3460	
4/1/2016	4/4/2014	Financial Swap	3226746	IFERC	Henry Hub			$4.0765	
5/1/2016	4/4/2014	Financial Swap	3226746	IFERC	Henry Hub			$4.0895	
6/1/2016	4/4/2014	Financial Swap	3226746	IFERC	Henry Hub			$4.1045	
7/1/2016	4/4/2014	Financial Swap	3226746	IFERC	Henry Hub			$4.1235	

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Delivery Month	Trade Date	Instrument	Trade Number	Market	Location	Volume MMBtu	Trade Price ($/MMBtu)	Market Price on Trade Date	Percent Difference from Trade Price
4/1/2016	4/11/2014	Financial Swap	3226752	IFERC	Henry Hub			$4.0995	
5/1/2016	4/11/2014	Financial Swap	3226752	IFERC	Henry Hub			$4.1065	
6/1/2016	4/11/2014	Financial Swap	3226752	IFERC	Henry Hub			$4.1235	
7/1/2016	4/11/2014	Financial Swap	3226752	IFERC	Henry Hub			$4.1425	
1/1/2016	4/14/2014	Financial Swap	3226754	IFERC	Transco Zone 4			$4.4880	
2/1/2016	4/14/2014	Financial Swap	3226754	IFERC	Transco Zone 4			$4.4600	
3/1/2016	4/14/2014	Financial Swap	3226754	IFERC	Transco Zone 4			$4.3980	
4/1/2016	4/28/2014	Financial Swap	3226757	IFERC	Henry Hub			$4.1525	
5/1/2016	4/28/2014	Financial Swap	3226757	IFERC	Henry Hub			$4.1605	
6/1/2016	4/28/2014	Financial Swap	3226757	IFERC	Henry Hub			$4.1785	
7/1/2016	4/28/2014	Financial Swap	3226757	IFERC	Henry Hub			$4.1985	
1/1/2016	5/21/2014	Financial Swap	3226790	IFERC	Transco Zone 4			$4.4580	
2/1/2016	5/21/2014	Financial Swap	3226790	IFERC	Transco Zone 4			$4.4370	
3/1/2016	5/21/2014	Financial Swap	3226790	IFERC	Transco Zone 4			$4.3730	
1/1/2016	5/27/2014	Financial Swap	3226796	IFERC	Henry Hub			$4.4615	
2/1/2016	5/27/2014	Financial Swap	3226796	IFERC	Henry Hub			$4.4405	
3/1/2016	5/27/2014	Financial Swap	3226796	IFERC	Henry Hub			$4.3775	
1/1/2016	6/16/2014	Financial Swap	3226801	IFERC	Transco Zone 4			$4.5620	
2/1/2016	6/16/2014	Financial Swap	3226801	IFERC	Transco Zone 4			$4.5410	
3/1/2016	6/16/2014	Financial Swap	3226801	IFERC	Transco Zone 4			$4.4800	
1/1/2016	6/23/2014	Financial Swap	3226803	IFERC	Transco Zone 4			$4.4780	
2/1/2016	6/23/2014	Financial Swap	3226803	IFERC	Transco Zone 4			$4.4570	
3/1/2016	6/23/2014	Financial Swap	3226803	IFERC	Transco Zone 4			$4.3960	
4/1/2016	6/26/2014	Financial Swap	3228844	IFERC	Transco Zone 4			$4.0805	
5/1/2016	6/26/2014	Financial Swap	3228844	IFERC	Transco Zone 4			$4.0915	
6/1/2016	6/26/2014	Financial Swap	3228844	IFERC	Transco Zone 4			$4.1205	
7/1/2016	6/26/2014	Financial Swap	3228844	IFERC	Transco Zone 4			$4.1465	
1/1/2016	7/25/2014	Financial Swap	3238365	IFERC	Henry Hub			$4.1795	
2/1/2016	7/25/2014	Financial Swap	3238365	IFERC	Henry Hub			$4.1605	
3/1/2016	7/25/2014	Financial Swap	3238365	IFERC	Henry Hub			$4.1005	
1/1/2016	7/31/2014	Financial Swap	3240195	IFERC	Henry Hub			$4.2035	
2/1/2016	7/31/2014	Financial Swap	3240195	IFERC	Henry Hub			$4.1845	
3/1/2016	7/31/2014	Financial Swap	3240195	IFERC	Henry Hub			$4.1235	
1/1/2016	8/13/2014	Financial Swap	3243801	IFERC	Henry Hub			$4.2235	
2/1/2016	8/13/2014	Financial Swap	3243801	IFERC	Henry Hub			$4.1995	
3/1/2016	8/13/2014	Financial Swap	3243801	IFERC	Henry Hub			$4.1325	
4/1/2016	8/18/2014	Financial Swap	3245524	IFERC	Transco Zone 4			$3.9610	
5/1/2016	8/18/2014	Financial Swap	3245524	IFERC	Transco Zone 4			$3.9535	
6/1/2016	8/18/2014	Financial Swap	3245524	IFERC	Transco Zone 4			$3.9665	
7/1/2016	8/18/2014	Financial Swap	3245524	IFERC	Transco Zone 4			$3.9965	
1/1/2016	9/4/2014	Financial Swap	3251815	IFERC	Transco Zone 4			$4.2800	
2/1/2016	9/4/2014	Financial Swap	3251815	IFERC	Transco Zone 4			$4.2570	
3/1/2016	9/4/2014	Financial Swap	3251815	IFERC	Transco Zone 4			$4.1860	
1/1/2016	9/22/2014	Financial Swap	3257541	IFERC	Columbia Gulf			$4.1440	
2/1/2016	9/22/2014	Financial Swap	3257541	IFERC	Columbia Gulf			$4.1260	
3/1/2016	9/22/2014	Financial Swap	3257541	IFERC	Columbia Gulf			$4.0715	
4/1/2016	10/23/2014	Financial Swap	3267252	IFERC	Columbia Gulf			$3.6445	
5/1/2016	10/23/2014	Financial Swap	3267252	IFERC	Columbia Gulf			$3.6465	
6/1/2016	10/23/2014	Financial Swap	3267252	IFERC	Columbia Gulf			$3.6720	
7/1/2016	10/23/2014	Financial Swap	3267252	IFERC	Columbia Gulf			$3.6975	
1/1/2016	10/30/2014	Financial Swap	3269357	IFERC	Columbia Gulf			$3.9890	
2/1/2016	10/30/2014	Financial Swap	3269357	IFERC	Columbia Gulf			$3.9700	
3/1/2016	10/30/2014	Financial Swap	3269357	IFERC	Columbia Gulf			$3.9115	
4/1/2016	11/18/2014	Financial Swap	3275165	IFERC	Columbia Gulf			$3.6925	
5/1/2016	11/18/2014	Financial Swap	3275165	IFERC	Columbia Gulf			$3.6815	
6/1/2016	11/18/2014	Financial Swap	3275165	IFERC	Columbia Gulf			$3.7000	
7/1/2016	11/18/2014	Financial Swap	3275165	IFERC	Columbia Gulf			$3.7225	
4/1/2016	12/15/2014	Financial Swap	3283780	IFERC	Columbia Gulf			$3.5875	
5/1/2016	12/15/2014	Financial Swap	3283780	IFERC	Columbia Gulf			$3.5865	
6/1/2016	12/15/2014	Financial Swap	3283780	IFERC	Columbia Gulf			$3.6130	
7/1/2016	12/15/2014	Financial Swap	3283780	IFERC	Columbia Gulf			$3.6425	
1/1/2016	12/23/2014	Financial Swap	3286345	NYMEX NG L1D	Henry Hub			$3.6970	
2/1/2016	12/23/2014	Financial Swap	3286345	NYMEX NG L1D	Henry Hub			$3.6970	
3/1/2016	12/23/2014	Financial Swap	3286345	NYMEX NG L1D	Henry Hub			$3.6520	
4/1/2016	12/23/2014	Financial Swap	3286346	IFERC	Columbia Gulf			$3.4005	
5/1/2016	12/23/2014	Financial Swap	3286346	IFERC	Columbia Gulf			$3.4035	
6/1/2016	12/23/2014	Financial Swap	3286346	IFERC	Columbia Gulf			$3.4310	
7/1/2016	12/23/2014	Financial Swap	3286346	IFERC	Columbia Gulf			$3.4645	
1/1/2016	1/20/2015	Financial Swap	3294865	NYMEX NG L1D	Henry Hub			$3.3800	
2/1/2016	1/20/2015	Financial Swap	3294865	NYMEX NG L1D	Henry Hub			$3.3780	
3/1/2016	1/20/2015	Financial Swap	3294865	NYMEX NG L1D	Henry Hub			$3.3390	
1/1/2016	1/29/2015	Financial Swap	3297902	IFERC	Transco Zone 4			$3.3380	
2/1/2016	1/29/2015	Financial Swap	3297902	IFERC	Transco Zone 4			$3.3350	
3/1/2016	1/29/2015	Financial Swap	3297902	IFERC	Transco Zone 4			$3.3030	
4/1/2016	1/30/2015	Financial Swap	3298141	IFERC	Transco Zone 4			$3.1625	
5/1/2016	1/30/2015	Financial Swap	3298141	IFERC	Transco Zone 4			$3.1610	
6/1/2016	1/30/2015	Financial Swap	3298141	IFERC	Transco Zone 4			$3.1915	
7/1/2016	1/30/2015	Financial Swap	3298141	IFERC	Transco Zone 4			$3.2375	
1/1/2016	2/9/2015	Financial Swap	3301240	IFERC	Transco Zone 4			$3.2905	
2/1/2016	2/9/2015	Financial Swap	3301240	IFERC	Transco Zone 4			$3.2815	
3/1/2016	2/9/2015	Financial Swap	3301240	IFERC	Transco Zone 4			$3.2495	
1/1/2016	2/23/2015	Financial Swap	3306467	NYMEX NG L1D	Henry Hub			$3.3620	
2/1/2016	2/23/2015	Financial Swap	3306467	NYMEX NG L1D	Henry Hub			$3.3420	
3/1/2016	2/23/2015	Financial Swap	3306467	NYMEX NG L1D	Henry Hub			$3.2920	
1/1/2016	2/26/2015	Financial Swap	3307909	NYMEX NG L1D	Henry Hub			$3.2550	
2/1/2016	2/26/2015	Financial Swap	3307909	NYMEX NG L1D	Henry Hub			$3.2460	
3/1/2016	2/26/2015	Financial Swap	3307909	NYMEX NG L1D	Henry Hub			$3.1970	
1/1/2016	3/4/2015	Financial Swap	3310403	IFERC	Transco Zone 4			$3.3235	
2/1/2016	3/4/2015	Financial Swap	3310403	IFERC	Transco Zone 4			$3.3115	
3/1/2016	3/4/2015	Financial Swap	3310403	IFERC	Transco Zone 4			$3.2585	
1/1/2016	3/9/2015	Financial Swap	3312109	IFERC	Transco Zone 4			$3.2565	
2/1/2016	3/9/2015	Financial Swap	3312109	IFERC	Transco Zone 4			$3.2475	
3/1/2016	3/9/2015	Financial Swap	3312109	IFERC	Transco Zone 4			$3.2055	
1/1/2016	3/25/2015	Financial Swap	3317625	IFERC	Transco Zone 4			$3.2765	
2/1/2016	3/25/2015	Financial Swap	3317625	IFERC	Transco Zone 4			$3.2635	
3/1/2016	3/25/2015	Financial Swap	3317625	IFERC	Transco Zone 4			$3.2105	
4/1/2016	3/25/2015	Financial Swap	3317627	IFERC	Transco Zone 4			$3.0745	
5/1/2016	3/25/2015	Financial Swap	3317627	IFERC	Transco Zone 4			$3.0650	
6/1/2016	3/25/2015	Financial Swap	3317627	IFERC	Transco Zone 4			$3.0845	
7/1/2016	3/25/2015	Financial Swap	3317627	IFERC	Transco Zone 4			$3.1215	
1/1/2016	4/9/2015	Financial Swap	3321456	NYMEX NG L1D	Henry Hub			$3.1040	
2/1/2016	4/9/2015	Financial Swap	3321456	NYMEX NG L1D	Henry Hub			$3.0970	
3/1/2016	4/9/2015	Financial Swap	3321456	NYMEX NG L1D	Henry Hub			$3.0570	

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Delivery Month	Trade Date	Instrument	Trade Number	Market	Location	Volume MMBtu	Trade Price ($/MMBtu)	Market Price on Trade Date	Percent Difference from Trade Price		
1/1/2016	4/16/2015	Financial Swap	3322458	NYMEX NG L1D	Henry Hub			$3.2010		5.4%	See Note 1 Below, item #1
2/1/2016	4/16/2015	Financial Swap	3322458	NYMEX NG L1D	Henry Hub			$3.1890		Avg for the Strip	Avg for entire strip was 3.1%
3/1/2016	4/16/2015	Financial Swap	3322458	NYMEX NG L1D	Henry Hub			$3.1430			
1/1/2016	4/20/2015	Financial Swap	3323024	IFERC	Transco Zone 4			$3.0970			
2/1/2016	4/20/2015	Financial Swap	3323024	IFERC	Transco Zone 4			$3.0890			
3/1/2016	4/20/2015	Financial Swap	3323024	IFERC	Transco Zone 4			$3.0440			
4/1/2016	4/20/2015	Financial Swap	3323025	IFERC	Transco Zone 4			$2.9180			
5/1/2016	4/20/2015	Financial Swap	3323025	IFERC	Transco Zone 4			$2.9330			
6/1/2016	4/20/2015	Financial Swap	3323025	IFERC	Transco Zone 4			$2.9890			
7/1/2016	4/20/2015	Financial Swap	3323025	IFERC	Transco Zone 4			$3.0070			
1/1/2016	4/27/2015	Financial Swap	3324164	IFERC	Transco Zone 4			$3.0935			
2/1/2016	4/27/2015	Financial Swap	3324164	IFERC	Transco Zone 4			$3.0865			
3/1/2016	4/27/2015	Financial Swap	3324164	IFERC	Transco Zone 4			$3.0440			
4/1/2016	5/20/2015	Financial Swap	3329156	IFERC	Transco Zone 4			$3.1405			
5/1/2016	5/20/2015	Financial Swap	3329156	IFERC	Transco Zone 4			$3.1345			
6/1/2016	5/20/2015	Financial Swap	3329156	IFERC	Transco Zone 4			$3.1575			
7/1/2016	5/20/2015	Financial Swap	3329156	IFERC	Transco Zone 4			$3.1905			
1/1/2016	5/29/2015	Financial Swap	3330749	IFERC	Columbia Gulf			$3.0330			
2/1/2016	5/29/2015	Financial Swap	3330749	IFERC	Columbia Gulf			$3.0425			
3/1/2016	5/29/2015	Financial Swap	3330749	IFERC	Columbia Gulf			$2.9945			
4/1/2016	6/15/2015	Financial Swap	3333884	IFERC	Transco Zone 4			$3.1275			
5/1/2016	6/15/2015	Financial Swap	3333884	IFERC	Transco Zone 4			$3.1205			
6/1/2016	6/15/2015	Financial Swap	3333884	IFERC	Transco Zone 4			$3.1415			
7/1/2016	6/15/2015	Financial Swap	3333884	IFERC	Transco Zone 4			$3.1775			
4/1/2016	7/17/2015	Financial Swap	3340042	IFERC	Transco Zone 4			$3.0845			
5/1/2016	7/17/2015	Financial Swap	3340042	IFERC	Transco Zone 4			$3.0755			
6/1/2016	7/17/2015	Financial Swap	3340042	IFERC	Transco Zone 4			$3.0955			
7/1/2016	7/17/2015	Financial Swap	3340042	IFERC	Transco Zone 4			$3.1255			
4/1/2016	7/21/2015	Financial Swap	3340909	IFERC	Transco Zone 4			$3.1085			
5/1/2016	7/21/2015	Financial Swap	3340909	IFERC	Transco Zone 4			$3.0995			
6/1/2016	7/21/2015	Financial Swap	3340909	IFERC	Transco Zone 4			$3.1205			
7/1/2016	7/21/2015	Financial Swap	3340909	IFERC	Transco Zone 4			$3.1495			
4/1/2016	8/6/2015	Financial Swap	3345068	IFERC	Transco Zone 4			$2.9880			
5/1/2016	8/6/2015	Financial Swap	3345068	IFERC	Transco Zone 4			$2.9800			
6/1/2016	8/6/2015	Financial Swap	3345068	IFERC	Transco Zone 4			$3.0010			
7/1/2016	8/6/2015	Financial Swap	3345068	IFERC	Transco Zone 4			$3.0310			
4/1/2016	8/21/2015	Financial Swap	3348333	IFERC	Transco Zone 4			$2.8820			
5/1/2016	8/21/2015	Financial Swap	3348333	IFERC	Transco Zone 4			$2.8740			
6/1/2016	8/21/2015	Financial Swap	3348333	IFERC	Transco Zone 4			$2.8980			
7/1/2016	8/21/2015	Financial Swap	3348333	IFERC	Transco Zone 4			$2.9360			
4/1/2016	8/25/2015	Financial Swap	3349168	IFERC	Transco Zone 4			$2.8405			
5/1/2016	8/25/2015	Financial Swap	3349168	IFERC	Transco Zone 4			$2.8315			
6/1/2016	8/25/2015	Financial Swap	3349168	IFERC	Transco Zone 4			$2.8565			
7/1/2016	8/25/2015	Financial Swap	3349168	IFERC	Transco Zone 4			$2.8945			
4/1/2016	9/10/2015	Financial Swap	3352499	IFERC	Transco Zone 4			$2.8695			
5/1/2016	9/10/2015	Financial Swap	3352499	IFERC	Transco Zone 4			$2.8645			
6/1/2016	9/10/2015	Financial Swap	3352499	IFERC	Transco Zone 4			$2.8905			
7/1/2016	9/10/2015	Financial Swap	3352499	IFERC	Transco Zone 4			$2.9255			
4/1/2016	9/14/2015	Financial Swap	3353288	IFERC	Transco Zone 4			$2.9035			
5/1/2016	9/14/2015	Financial Swap	3353288	IFERC	Transco Zone 4			$2.8955			
6/1/2016	9/14/2015	Financial Swap	3353288	IFERC	Transco Zone 4			$2.9175			
7/1/2016	9/14/2015	Financial Swap	3353288	IFERC	Transco Zone 4			$2.9485			
4/1/2016	9/16/2015	Financial Swap	3353713	IFERC	Transco Zone 4			$2.8425			
5/1/2016	9/16/2015	Financial Swap	3353713	IFERC	Transco Zone 4			$2.8355			
6/1/2016	9/16/2015	Financial Swap	3353713	IFERC	Transco Zone 4			$2.8575			
7/1/2016	9/16/2015	Financial Swap	3353713	IFERC	Transco Zone 4			$2.8905			
1/1/2016	10/1/2015	Financial Swap	3356603	IFERC	Transco Zone 4			$2.7880			
2/1/2016	10/1/2015	Financial Swap	3356603	IFERC	Transco Zone 4			$2.7825			
3/1/2016	10/1/2015	Financial Swap	3356603	IFERC	Transco Zone 4			$2.7540			
4/1/2016	10/1/2015	Financial Swap	3356604	IFERC	Transco Zone 4			$2.6365			
5/1/2016	10/1/2015	Financial Swap	3356604	IFERC	Transco Zone 4			$2.6415			
6/1/2016	10/1/2015	Financial Swap	3356604	IFERC	Transco Zone 4			$2.6725			
7/1/2016	10/1/2015	Financial Swap	3356604	IFERC	Transco Zone 4			$2.7105			
4/1/2016	10/2/2015	Financial Swap	3356822	IFERC	Transco Zone 4			$2.6610			
5/1/2016	10/2/2015	Financial Swap	3356822	IFERC	Transco Zone 4			$2.6660			
6/1/2016	10/2/2015	Financial Swap	3356822	IFERC	Transco Zone 4			$2.6970			
7/1/2016	10/2/2015	Financial Swap	3356822	IFERC	Transco Zone 4			$2.7350			
4/1/2016	10/12/2015	Financial Swap	3358458	IFERC	Transco Zone 4			$2.7490			
5/1/2016	10/12/2015	Financial Swap	3358458	IFERC	Transco Zone 4			$2.7540			
6/1/2016	10/12/2015	Financial Swap	3358458	IFERC	Transco Zone 4			$2.7875			
7/1/2016	10/12/2015	Financial Swap	3358458	IFERC	Transco Zone 4			$2.8265			
5/1/2016	10/15/2015	Financial Swap	3359032	IFERC	Henry Hub			$2.6930			
6/1/2016	10/15/2015	Financial Swap	3359032	IFERC	Henry Hub			$2.7300			
7/1/2016	10/15/2015	Financial Swap	3359032	IFERC	Henry Hub			$2.7710			
5/1/2016	10/21/2015	Financial Swap	3360082	IFERC	Henry Hub			$2.6580			
6/1/2016	10/21/2015	Financial Swap	3360082	IFERC	Henry Hub			$2.6960			
7/1/2016	10/21/2015	Financial Swap	3360082	IFERC	Henry Hub			$2.7380			
5/1/2016	10/23/2015	Financial Swap	3360554	IFERC	Henry Hub			$2.5790			
6/1/2016	10/23/2015	Financial Swap	3360554	IFERC	Henry Hub			$2.6190			
7/1/2016	10/23/2015	Financial Swap	3360554	IFERC	Henry Hub			$2.6650			
5/1/2016	11/6/2015	Financial Swap	3363536	IFERC	Henry Hub			$2.5370			
6/1/2016	11/6/2015	Financial Swap	3363536	IFERC	Henry Hub			$2.5810			
7/1/2016	11/6/2015	Financial Swap	3363536	IFERC	Henry Hub			$2.6280			
5/1/2016	11/11/2015	Financial Swap	3364483	IFERC	Henry Hub			$2.5100			
6/1/2016	11/11/2015	Financial Swap	3364483	IFERC	Henry Hub			$2.5570			
7/1/2016	11/11/2015	Financial Swap	3364483	IFERC	Henry Hub			$2.6050			
1/1/2016	11/11/2015	Financial Swap	3364485	NYMEX NG L1D	Henry Hub			$2.4520			
2/1/2016	11/11/2015	Financial Swap	3364485	NYMEX NG L1D	Henry Hub			$2.4920			
5/1/2016	11/12/2015	Financial Swap	3364688	IFERC	Henry Hub			$2.5180			
6/1/2016	11/12/2015	Financial Swap	3364688	IFERC	Henry Hub			$2.5650			
7/1/2016	11/12/2015	Financial Swap	3364688	IFERC	Henry Hub			$2.6140			
4/1/2016	11/16/2015	Financial Swap	3365343	IFERC	Columbia Gulf			$2.4810			
5/1/2016	11/16/2015	Financial Swap	3365343	IFERC	Columbia Gulf			$2.4920			
6/1/2016	11/16/2015	Financial Swap	3365343	IFERC	Columbia Gulf			$2.5345			
7/1/2016	11/16/2015	Financial Swap	3365343	IFERC	Columbia Gulf			$2.5765			
4/1/2016	11/18/2015	Financial Swap	3365804	IFERC	Columbia Gulf			$2.4335			
5/1/2016	11/18/2015	Financial Swap	3365804	IFERC	Columbia Gulf			$2.4435			
6/1/2016	11/18/2015	Financial Swap	3365804	IFERC	Columbia Gulf			$2.4850			
7/1/2016	11/18/2015	Financial Swap	3365804	IFERC	Columbia Gulf			$2.5240			
5/1/2016	12/2/2015	Financial Swap	3368346	NYMEX NG L1D	Henry Hub			$2.3520			
6/1/2016	12/2/2015	Financial Swap	3368346	NYMEX NG L1D	Henry Hub			$2.3990			
7/1/2016	12/2/2015	Financial Swap	3368346	NYMEX NG L1D	Henry Hub			$2.4480			
6/1/2016	12/4/2015	Financial Swap	3368666	IFERC	Transco Zone 4			$2.4075			

REDACTED

Delivery Month	Trade Date	Instrument	Trade Number	Market	Location	Volume MMBtu	Trade Price ($/MMBtu)	Market Price on Trade Date	Percent Difference from Trade Price
7/1/2016	12/4/2015	Financial Swap	3368666	IFERC	Transco Zone 4			$2.4535	
8/1/2016	12/7/2015	Financial Swap	3369208	IFERC	Transco Zone 4			$2.3425	
7/1/2016	12/7/2015	Financial Swap	3369208	IFERC	Transco Zone 4			$2.3925	
1/1/2016	12/11/2015	Financial Swap	3370065	NYMEX NG L1D	Henry Hub			$1.9900	
2/1/2016	12/11/2015	Financial Swap	3370065	NYMEX NG L1D	Henry Hub			$2.0500	
6/1/2016	12/11/2015	Financial Swap	3370066	IFERC	Transco Zone 4			$2.3185	
7/1/2016	12/11/2015	Financial Swap	3370066	IFERC	Transco Zone 4			$2.3760	
8/1/2016	12/14/2015	Financial Swap	3370568	IFERC	Transco Zone 4			$2.2405	
7/1/2016	12/14/2015	Financial Swap	3370568	IFERC	Transco Zone 4			$2.3000	
1/1/2016	12/15/2015	Financial Swap	3370773	IFERC	Transco Zone 4			$1.8395	
2/1/2016	12/15/2015	Financial Swap	3370773	IFERC	Transco Zone 4			$1.9010	
3/1/2016	12/15/2015	Financial Swap	3370773	IFERC	Transco Zone 4			$1.9525	
1/1/2016	12/16/2015	Financial Swap	3371050	NYMEX NG L1D	Henry Hub			$1.7900	
8/1/2016	1/6/2016	Financial Swap	3374592	IFERC	Transco Zone 4			$2.4435	
7/1/2016	1/6/2016	Financial Swap	3374592	IFERC	Transco Zone 4			$2.4960	
8/1/2016	1/19/2016	Financial Swap	3376795	IFERC	Transco Zone 4			$2.3140	
7/1/2016	1/19/2016	Financial Swap	3376795	IFERC	Transco Zone 4			$2.3755	
8/1/2016	1/25/2016	Financial Swap	3377979	IFERC	Transco Zone 4			$2.3780	
7/1/2016	1/25/2016	Financial Swap	3377979	IFERC	Transco Zone 4			$2.4365	
6/1/2016	2/18/2016	Financial Swap	3382168	NYMEX NG L1D	Henry Hub			$2.0770	
7/1/2016	2/18/2016	Financial Swap	3382168	NYMEX NG L1D	Henry Hub			$2.1500	
8/1/2016	2/25/2016	Financial Swap	3383267	NYMEX NG L1D	Henry Hub			$1.9440	
7/1/2016	2/25/2016	Financial Swap	3383267	NYMEX NG L1D	Henry Hub			$2.0190	

* Percentage difference from trade price - Negative identifies when a trade price is above the closing market price for the respective day based on the simplified comparison.
* Percentage difference from trade price - Positive identifies when a trade price is below the closing market price for the respective day based on the simplified comparison.

Note 1
These trades below were strip trades for multiple months. Due to the test period of the request being different than the actual months of the strip deals executed, this causes the appearance of trades being more than 5% different from the market price for the respective day based on the simplified comparison. Below, the entire strips have been put together to show the trades were not 5% different than market when in complete form. All trades are executed at the prevailing market price at the time of the trade.

Item #1									
11/1/2015	4/16/2015	Financial Swap	3322458	NYMEX NG L1D	Henry Hub			$2.9220		3.1%
12/1/2015	4/16/2015	Financial Swap	3322458	NYMEX NG L1D	Henry Hub			$3.0960		Avg for the Strip
1/1/2016	4/16/2015	Financial Swap	3322458	NYMEX NG L1D	Henry Hub			$3.2010		
2/1/2016	4/16/2015	Financial Swap	3322458	NYMEX NG L1D	Henry Hub			$3.1890		
3/1/2016	4/16/2015	Financial Swap	3322458	NYMEX NG L1D	Henry Hub			$3.1430		

REDACTED

Question 24
2016 January - July Storage Swap Hedges

Delivery Month	Trade Date	Instrument	Trade Number	Market	Location	Volume MMBtu	Trade Price ($/MMBtu)	Market Price on Trade Date	Percent Difference from Trade Price
6/1/2016	2/26/2016	Financial Swap	3383865	IFERC	FGTZ3			$1.9460	

There were no storage hedges done between August 2015 and May 2016

* Percentage difference from trade price - Negative identifies when a trade price is above the closing market price for the respective day based on the simplified comparison.
* Percentage difference from trade price - Positive identifies when a trade price is below the closing market price for the respective day based on the simplified comparison.

REDACTED

2015 August - December Swap Hedges
Light Fuel Oil

Delivery Month	Trade Date	Instrument	Trade Number	Market	Location	Volume (Gallons)	Trade Price ($/Gallons)	Market Price on Trade Date ($/Gallons)	Percent Difference from Trade Price
8/1/2015	12/4/2014	FIXED SWAP	3280065	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$2.1128	
9/1/2015	12/4/2014	FIXED SWAP	3280065	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$2.1280	
10/1/2015	12/4/2014	FIXED SWAP	3280065	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$2.1334	
11/1/2015	12/4/2014	FIXED SWAP	3280065	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$2.1161	
12/1/2015	12/4/2014	FIXED SWAP	3280065	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$2.1122	

Light Fuel Oil prices and quantities are traded financially in gallons.

* Percentage difference from trade price - Negative identifies when a trade price is above the closing market price for the respective day based on the simplified comparison.
* Percentage difference from trade price - Positive identifies when a trade price is below the closing market price for the respective day based on the simplified comparison.

Note 1
Due to the test period of the request being different than the actual months of the strip deals executed, this causes the appearance of trades being more than 5% different from the market price for the respective day based on the simplified comparison.

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2015 August - December Fuel Oil Swap Hedges - Barge
Light Fuel Oil

Delivery Month	Trade Date	Instrument	Trade Number	Market	Location	Volume (Gallons)	Trade Price ($/Gallons)	Market Price on Trade Date ($/Gallons)	Percent Difference from Trade Price
8/1/2015	1/2/2015	FIXED SWAP	3288977	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.8178	
8/1/2015	1/2/2015	FIXED SWAP	3288978	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.8178	
9/1/2015	1/2/2015	FIXED SWAP	3288977	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.8392	
9/1/2015	1/2/2015	FIXED SWAP	3288978	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.8392	
10/1/2015	1/29/2015	FIXED SWAP	3297786	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.6615	
11/1/2015	1/29/2015	FIXED SWAP	3297786	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.6572	
12/1/2015	1/29/2015	FIXED SWAP	3311032	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.6545	

Light Fuel Oil prices and quantities are traded financially in gallons.

Question 25
2015 August - December Fuel Oil Swap Hedges - Rail
Light Fuel Oil

Delivery Month	Trade Date	Instrument	Trade Number	Market	Location	Volume (Gallons)	Trade Price ($/Gallons)	Market Price on Trade Date ($/Gallons)	Percent Difference from Trade Price
8/1/2015	5/21/2015	FIXED SWAP	3329255	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.9593	
9/1/2015	5/21/2015	FIXED SWAP	3329255	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.9788	

Light Fuel Oil prices and quantities are traded financially in gallons.

* Percentage difference from trade price - Negative identifies when a trade price is above the closing market price for the respective day based on the simplified comparison.
* Percentage difference from trade price - Positive identifies when a trade price is below the closing market price for the respective day based on the simplified comparison.

Note 1
Due to the test period of the request being different than the actual months of the strip deals executed, this causes the appearance of trades being more than 5% different from the market price for the respective day based on the simplified comparison.

REDACTED

2016 January - July Fuel Oil Swap Hedges - Barge
Light Fuel Oil

Delivery Month	Trade Date	Instrument	Trade Number	Market	Location	Volume (Gallons)	Trade Price ($/Gallons)	Market Price on Trade Date ($/Gallons)	Percent Difference from Trade Price	
1/1/2016	12/14/2015	Financial Swap	3370647	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.0836		
2/1/2016	12/14/2015	Financial Swap	3370647	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1296		
3/1/2016	12/14/2015	Financial Swap	3370647	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1636		
1/1/2016	12/14/2015	Financial Swap	3370646	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.0836		1.5% vg for the Strip
2/1/2016	12/14/2015	Financial Swap	3370646	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1296		
3/1/2016	12/14/2015	Financial Swap	3370646	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1636		
1/1/2016	12/14/2015	Financial Swap	3370674	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.0836		1.8% vg for the Strip
2/1/2016	12/14/2015	Financial Swap	3370674	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1296		
3/1/2016	12/14/2015	Financial Swap	3370674	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1636		
1/1/2016	12/15/2015	Financial Swap	3370776	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.0701		4.0% vg for the Strip
2/1/2016	12/15/2015	Financial Swap	3370776	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1233		
3/1/2016	12/15/2015	Financial Swap	3370776	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1635		
1/1/2016	12/16/2015	Financial Swap	3371053	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.0959		
2/1/2016	12/16/2015	Financial Swap	3371053	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1423		
3/1/2016	12/16/2015	Financial Swap	3371053	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1291		
4/1/2016	1/7/2016	Financial Swap	3374757	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.0734		
5/1/2016	1/7/2016	Financial Swap	3374757	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.0958		
6/1/2016	1/7/2016	Financial Swap	3374757	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1194		
7/1/2016	1/12/2016	Financial Swap	3375682	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.0843		
4/1/2016	2/11/2016	Financial Swap	3380940	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$0.9499		3.7% vg for the Strip
5/1/2016	2/11/2016	Financial Swap	3380940	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$0.9634		
6/1/2016	2/11/2016	Financial Swap	3380940	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$0.9811		
7/1/2016	2/11/2016	Financial Swap	3380940	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.0039		
4/1/2016	3/3/2016	Financial Swap	3384449	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.0728		
5/1/2016	3/3/2016	Financial Swap	3384449	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.0890		
6/1/2016	3/3/2016	Financial Swap	3384449	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1065		
7/1/2016	3/3/2016	Financial Swap	3384449	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1289		
4/1/2016	3/14/2016	Financial Swap	3386308	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1812		
5/1/2016	3/14/2016	Financial Swap	3386308	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1915		
6/1/2016	3/14/2016	Financial Swap	3386308	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.2042		
7/1/2016	3/14/2016	Financial Swap	3386308	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.2214		
4/1/2016	3/16/2016	Financial Swap	3386741	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1358		4.9% vg for the Strip
5/1/2016	3/16/2016	Financial Swap	3386741	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1459		
6/1/2016	3/16/2016	Financial Swap	3386741	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1616		
7/1/2016	3/16/2016	Financial Swap	3386741	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1800		
4/1/2016	3/18/2016	Financial Swap	3387221	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.2124		
5/1/2016	3/18/2016	Financial Swap	3387221	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.2211		
6/1/2016	3/18/2016	Financial Swap	3387221	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.2346		
7/1/2016	3/18/2016	Financial Swap	3387221	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.2503		
4/1/2016	3/18/2016	Financial Swap	3387222	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.2124		
5/1/2016	3/18/2016	Financial Swap	3387222	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.2211		
6/1/2016	3/18/2016	Financial Swap	3387222	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.2346		
7/1/2016	3/18/2016	Financial Swap	3387222	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.2503		
4/1/2016	3/24/2016	Financial Swap	3388336	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1500		
5/1/2016	3/24/2016	Financial Swap	3388336	Gulfcoast Pipe ULSD	Gulf Coast Pipeline			$1.1678		

Light Fuel Oil prices and quantities are traded financially in gallons.

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Note 1
Due to the test period of the request being different than the actual months of the strip deals executed, this causes the appearance of trades being more than 5% different from the market price for the respective day based on the simplified comparison.

REDACTED

2015 August - December Options

Delivery Month	Trade Date	Instrument	Trade Number	Put/Call	Market	Location	Strike Price	Trade Price ($/MMBtu)	Settled Quantity MMBtu
8/1/2015	1/9/2013	Financial Option	3227307	Call	NYMEX NG L1D	Henry Hub			
8/1/2015	1/9/2013	Financial Option	3227307	Put	NYMEX NG L1D	Henry Hub			
9/1/2015	1/9/2013	Financial Option	3227307	Call	NYMEX NG L1D	Henry Hub			
9/1/2015	1/9/2013	Financial Option	3227307	Put	NYMEX NG L1D	Henry Hub			
10/1/2015	1/9/2013	Financial Option	3227307	Call	NYMEX NG L1D	Henry Hub			
10/1/2015	1/9/2013	Financial Option	3227307	Put	NYMEX NG L1D	Henry Hub			
11/1/2015	1/9/2013	Financial Option	3227307	Call	NYMEX NG L1D	Henry Hub			
11/1/2015	1/9/2013	Financial Option	3227307	Put	NYMEX NG L1D	Henry Hub			
12/1/2015	1/9/2013	Financial Option	3227307	Call	NYMEX NG L1D	Henry Hub			
12/1/2015	1/9/2013	Financial Option	3227307	Put	NYMEX NG L1D	Henry Hub			
8/1/2015	1/28/2013	Financial Option	3227311	Call	NYMEX NG L1D	Henry Hub			
8/1/2015	1/28/2013	Financial Option	3227311	Put	NYMEX NG L1D	Henry Hub			
9/1/2015	1/28/2013	Financial Option	3227311	Call	NYMEX NG L1D	Henry Hub			
9/1/2015	1/28/2013	Financial Option	3227311	Put	NYMEX NG L1D	Henry Hub			
10/1/2015	1/28/2013	Financial Option	3227311	Call	NYMEX NG L1D	Henry Hub			
10/1/2015	1/28/2013	Financial Option	3227311	Put	NYMEX NG L1D	Henry Hub			
11/1/2015	1/28/2013	Financial Option	3227311	Call	NYMEX NG L1D	Henry Hub			
11/1/2015	1/28/2013	Financial Option	3227311	Put	NYMEX NG L1D	Henry Hub			
12/1/2015	1/28/2013	Financial Option	3227311	Call	NYMEX NG L1D	Henry Hub			
12/1/2015	1/28/2013	Financial Option	3227311	Put	NYMEX NG L1D	Henry Hub			
8/1/2015	6/4/2013	Financial Option	3227312	Call	IFERC	Columbia Gulf			
8/1/2015	6/4/2013	Financial Option	3227312	Put	IFERC	Columbia Gulf			
9/1/2015	6/4/2013	Financial Option	3227312	Call	IFERC	Columbia Gulf			
9/1/2015	6/4/2013	Financial Option	3227312	Put	IFERC	Columbia Gulf			
10/1/2015	6/4/2013	Financial Option	3227312	Call	IFERC	Columbia Gulf			
10/1/2015	6/4/2013	Financial Option	3227312	Put	IFERC	Columbia Gulf			
11/1/2015	6/4/2013	Financial Option	3227312	Call	IFERC	Columbia Gulf			
11/1/2015	6/4/2013	Financial Option	3227312	Put	IFERC	Columbia Gulf			
12/1/2015	6/4/2013	Financial Option	3227312	Call	IFERC	Columbia Gulf			
12/1/2015	6/4/2013	Financial Option	3227312	Put	IFERC	Columbia Gulf			
8/1/2015	2/10/2014	Financial Option	3227767	Call	IFERC	Transco Zone 4			
8/1/2015	2/10/2014	Financial Option	3227767	Put	IFERC	Transco Zone 4			
9/1/2015	2/10/2014	Financial Option	3227767	Call	IFERC	Transco Zone 4			
9/1/2015	2/10/2014	Financial Option	3227767	Put	IFERC	Transco Zone 4			
10/1/2015	2/10/2014	Financial Option	3227767	Call	IFERC	Transco Zone 4			
10/1/2015	2/10/2014	Financial Option	3227767	Put	IFERC	Transco Zone 4			
8/1/2015	4/14/2014	Financial Option	3227518	Call	IFERC	Henry Hub			
8/1/2015	4/14/2014	Financial Option	3227518	Put	IFERC	Henry Hub			
9/1/2015	4/14/2014	Financial Option	3227518	Call	IFERC	Henry Hub			
9/1/2015	4/14/2014	Financial Option	3227518	Put	IFERC	Henry Hub			
8/1/2015	5/16/2014	Financial Option	3227519	Call	NYMEX NG L1D	Henry Hub			
8/1/2015	5/16/2014	Financial Option	3227519	Put	NYMEX NG L1D	Henry Hub			
9/1/2015	5/16/2014	Financial Option	3227519	Call	NYMEX NG L1D	Henry Hub			
9/1/2015	5/16/2014	Financial Option	3227519	Put	NYMEX NG L1D	Henry Hub			
10/1/2015	5/16/2014	Financial Option	3227519	Call	NYMEX NG L1D	Henry Hub			
10/1/2015	5/16/2014	Financial Option	3227519	Put	NYMEX NG L1D	Henry Hub			
8/1/2015	6/10/2014	Financial Option	3227521	Call	NYMEX NG L1D	Henry Hub			
8/1/2015	6/10/2014	Financial Option	3227521	Put	NYMEX NG L1D	Henry Hub			
9/1/2015	6/10/2014	Financial Option	3227521	Call	NYMEX NG L1D	Henry Hub			
9/1/2015	6/10/2014	Financial Option	3227521	Put	NYMEX NG L1D	Henry Hub			
10/1/2015	6/10/2014	Financial Option	3227521	Call	NYMEX NG L1D	Henry Hub			
10/1/2015	6/10/2014	Financial Option	3227521	Put	NYMEX NG L1D	Henry Hub			
8/1/2015	7/21/2014	Financial Option	3238363	Call	IFERC	Henry Hub			
8/1/2015	7/21/2014	Financial Option	3238363	Put	IFERC	Henry Hub			
9/1/2015	7/21/2014	Financial Option	3238363	Call	IFERC	Henry Hub			
9/1/2015	7/21/2014	Financial Option	3238363	Put	IFERC	Henry Hub			
8/1/2015	8/20/2014	Financial Option	3246480	Call	IFERC	Henry Hub			
8/1/2015	8/20/2014	Financial Option	3246480	Put	IFERC	Henry Hub			
9/1/2015	8/20/2014	Financial Option	3246480	Call	IFERC	Henry Hub			
9/1/2015	8/20/2014	Financial Option	3246480	Put	IFERC	Henry Hub			
8/1/2015	9/3/2014	Financial Option	3251386	Call	IFERC	Henry Hub			
8/1/2015	9/3/2014	Financial Option	3251386	Put	IFERC	Henry Hub			
9/1/2015	9/3/2014	Financial Option	3251386	Call	IFERC	Henry Hub			
9/1/2015	9/3/2014	Financial Option	3251386	Put	IFERC	Henry Hub			
8/1/2015	10/13/2014	Financial Option	3264163	Call	IFERC	Henry Hub			
8/1/2015	10/13/2014	Financial Option	3264163	Put	IFERC	Henry Hub			
9/1/2015	10/13/2014	Financial Option	3264163	Call	IFERC	Henry Hub			
9/1/2015	10/13/2014	Financial Option	3264163	Put	IFERC	Henry Hub			
8/1/2015	10/20/2014	Financial Option	3266285	Call	IFERC	Henry Hub			
8/1/2015	10/20/2014	Financial Option	3266285	Put	IFERC	Henry Hub			
9/1/2015	10/20/2014	Financial Option	3266285	Call	IFERC	Henry Hub			

REDACTED

Delivery Month	Trade Date	Instrument	Trade Number	Put/Call	Market	Location	Strike Price	Trade Price ($/MMBtu)	Settled Quantity MMBtu
9/1/2015	10/20/2014	Financial Option	3266285	Put	IFERC	Henry Hub			
8/1/2015	12/3/2014	Financial Option	3279679	Call	IFERC	Henry Hub			
8/1/2015	12/3/2014	Financial Option	3279679	Put	IFERC	Henry Hub			
9/1/2015	12/3/2014	Financial Option	3279679	Call	IFERC	Henry Hub			
9/1/2015	12/3/2014	Financial Option	3279679	Put	IFERC	Henry Hub			
8/1/2015	1/12/2015	Financial Option	3292219	Call	IFERC	Henry Hub			
8/1/2015	1/12/2015	Financial Option	3292219	Put	IFERC	Henry Hub			
9/1/2015	1/12/2015	Financial Option	3292219	Call	IFERC	Henry Hub			
9/1/2015	1/12/2015	Financial Option	3292219	Put	IFERC	Henry Hub			
8/1/2015	1/30/2015	Financial Option	3298153	Call	NYMEX NG L1D	Henry Hub			
8/1/2015	1/30/2015	Financial Option	3298153	Put	NYMEX NG L1D	Henry Hub			
9/1/2015	1/30/2015	Financial Option	3298153	Call	NYMEX NG L1D	Henry Hub			
9/1/2015	1/30/2015	Financial Option	3298153	Put	NYMEX NG L1D	Henry Hub			
8/1/2015	2/9/2015	Financial Option	3301239	Call	NYMEX NG L1D	Henry Hub			
8/1/2015	2/9/2015	Financial Option	3301239	Put	NYMEX NG L1D	Henry Hub			
9/1/2015	2/9/2015	Financial Option	3301239	Call	NYMEX NG L1D	Henry Hub			
9/1/2015	2/9/2015	Financial Option	3301239	Put	NYMEX NG L1D	Henry Hub			
8/1/2015	2/17/2015	Financial Option	3304156	Call	NYMEX NG L1D	Henry Hub			
8/1/2015	2/17/2015	Financial Option	3304156	Put	NYMEX NG L1D	Henry Hub			
9/1/2015	2/17/2015	Financial Option	3304156	Call	NYMEX NG L1D	Henry Hub			
9/1/2015	2/17/2015	Financial Option	3304156	Put	NYMEX NG L1D	Henry Hub			
8/1/2015	3/4/2015	Financial Option	3310401	Call	NYMEX NG L1D	Henry Hub			
8/1/2015	3/4/2015	Financial Option	3310401	Put	NYMEX NG L1D	Henry Hub			
9/1/2015	3/4/2015	Financial Option	3310401	Call	NYMEX NG L1D	Henry Hub			
9/1/2015	3/4/2015	Financial Option	3310401	Put	NYMEX NG L1D	Henry Hub			
8/1/2015	3/9/2015	Financial Option	3312102	Call	NYMEX NG L1D	Henry Hub			
8/1/2015	3/9/2015	Financial Option	3312102	Put	NYMEX NG L1D	Henry Hub			
9/1/2015	3/9/2015	Financial Option	3312102	Call	NYMEX NG L1D	Henry Hub			
9/1/2015	3/9/2015	Financial Option	3312102	Put	NYMEX NG L1D	Henry Hub			
8/1/2015	3/25/2015	Financial Option	3317624	Call	NYMEX NG L1D	Henry Hub			
8/1/2015	3/25/2015	Financial Option	3317624	Put	NYMEX NG L1D	Henry Hub			
9/1/2015	3/25/2015	Financial Option	3317624	Call	NYMEX NG L1D	Henry Hub			
9/1/2015	3/25/2015	Financial Option	3317624	Put	NYMEX NG L1D	Henry Hub			
8/1/2015	4/10/2015	Financial Option	3321624	Call	NYMEX NG L1D	Henry Hub			
8/1/2015	4/10/2015	Financial Option	3321624	Put	NYMEX NG L1D	Henry Hub			
9/1/2015	4/10/2015	Financial Option	3321624	Call	NYMEX NG L1D	Henry Hub			
9/1/2015	4/10/2015	Financial Option	3321624	Put	NYMEX NG L1D	Henry Hub			
10/1/2015	4/10/2015	Financial Option	3321624	Call	NYMEX NG L1D	Henry Hub			
10/1/2015	4/10/2015	Financial Option	3321624	Put	NYMEX NG L1D	Henry Hub			
8/1/2015	5/15/2015	Financial Option	3327183	Call	NYMEX NG L1D	Henry Hub			
8/1/2015	5/15/2015	Financial Option	3327183	Put	NYMEX NG L1D	Henry Hub			
9/1/2015	5/15/2015	Financial Option	3327183	Call	NYMEX NG L1D	Henry Hub			
9/1/2015	5/15/2015	Financial Option	3327183	Put	NYMEX NG L1D	Henry Hub			
10/1/2015	5/15/2015	Financial Option	3327183	Call	NYMEX NG L1D	Henry Hub			
10/1/2015	5/15/2015	Financial Option	3327183	Put	NYMEX NG L1D	Henry Hub			
8/1/2015	5/19/2015	Financial Option	3328119	Call	NYMEX NG L1D	Henry Hub			
8/1/2015	5/19/2015	Financial Option	3328119	Put	NYMEX NG L1D	Henry Hub			
9/1/2015	5/19/2015	Financial Option	3328119	Call	NYMEX NG L1D	Henry Hub			
9/1/2015	5/19/2015	Financial Option	3328119	Put	NYMEX NG L1D	Henry Hub			
10/1/2015	5/19/2015	Financial Option	3328119	Call	NYMEX NG L1D	Henry Hub			
10/1/2015	5/19/2015	Financial Option	3328119	Put	NYMEX NG L1D	Henry Hub			
11/1/2015	5/19/2015	Financial Option	3328129	Call	NYMEX NG L1D	Henry Hub			
11/1/2015	5/19/2015	Financial Option	3328129	Put	NYMEX NG L1D	Henry Hub			
12/1/2015	5/19/2015	Financial Option	3328129	Call	NYMEX NG L1D	Henry Hub			
12/1/2015	5/19/2015	Financial Option	3328129	Put	NYMEX NG L1D	Henry Hub			
8/1/2015	6/10/2015	Financial Option	3332907	Call	NYMEX NG L1D	Henry Hub			
8/1/2015	6/10/2015	Financial Option	3332907	Put	NYMEX NG L1D	Henry Hub			
9/1/2015	6/10/2015	Financial Option	3332907	Call	NYMEX NG L1D	Henry Hub			
9/1/2015	6/10/2015	Financial Option	3332907	Put	NYMEX NG L1D	Henry Hub			
10/1/2015	6/10/2015	Financial Option	3332907	Call	NYMEX NG L1D	Henry Hub			
10/1/2015	6/10/2015	Financial Option	3332907	Put	NYMEX NG L1D	Henry Hub			
8/1/2015	6/16/2015	Financial Option	3334101	Call	IFERC	Transco Zone 4			
8/1/2015	6/16/2015	Financial Option	3334101	Put	IFERC	Transco Zone 4			
8/1/2015	6/24/2015	Financial Option	3336012	Call	IFERC	Transco Zone 4			
8/1/2015	6/24/2015	Financial Option	3336012	Put	IFERC	Transco Zone 4			
8/1/2015	6/25/2015	Financial Option	3336225	Call	NYMEX NG L1D	Henry Hub			
8/1/2015	6/25/2015	Financial Option	3336225	Put	NYMEX NG L1D	Henry Hub			
11/1/2015	8/18/2015	Financial Option	3347636	Call	NYMEX NG L1D	Henry Hub			
11/1/2015	8/18/2015	Financial Option	3347636	Put	NYMEX NG L1D	Henry Hub			
12/1/2015	8/18/2015	Financial Option	3347636	Call	NYMEX NG L1D	Henry Hub			
12/1/2015	8/18/2015	Financial Option	3347636	Put	NYMEX NG L1D	Henry Hub			
11/1/2015	8/21/2015	Financial Option	3348334	Call	NYMEX NG L1D	Henry Hub			
11/1/2015	8/21/2015	Financial Option	3348334	Put	NYMEX NG L1D	Henry Hub			
12/1/2015	8/21/2015	Financial Option	3348334	Call	NYMEX NG L1D	Henry Hub			
12/1/2015	8/21/2015	Financial Option	3348334	Put	NYMEX NG L1D	Henry Hub			
11/1/2015	9/9/2015	Financial Option	3352226	Call	NYMEX NG L1D	Henry Hub			
11/1/2015	9/9/2015	Financial Option	3352226	Put	NYMEX NG L1D	Henry Hub			
12/1/2015	9/9/2015	Financial Option	3352226	Call	NYMEX NG L1D	Henry Hub			
12/1/2015	9/9/2015	Financial Option	3352226	Put	NYMEX NG L1D	Henry Hub			

REDACTED

Delivery Month	Trade Date	Instrument	Trade Number	Put/Call	Market	Location	Strike Price	Trade Price ($/MMBtu)	Settled Quantity MMBtu
11/1/2015	9/18/2015	Financial Option	3354168	Call	NYMEX NG L1D	Henry Hub			
11/1/2015	9/18/2015	Financial Option	3354168	Put	NYMEX NG L1D	Henry Hub			
12/1/2015	9/18/2015	Financial Option	3354168	Call	NYMEX NG L1D	Henry Hub			
12/1/2015	9/18/2015	Financial Option	3354168	Put	NYMEX NG L1D	Henry Hub			

* No observable market indications or quotes available for options.

2016 January - July Swap Hedges

REDACTED

Delivery Month	Trade Date	Instrument	Trade Number	Put/Call	Market	Location	Strike Price	Trade Price ($/MMBtu)	Settled Quantity MMBtu
4/1/2016	11/5/2013	Financial Option	3227413	Call	NYMEX NG L1D	Henry Hub			
4/1/2016	11/5/2013	Financial Option	3227413	Put	NYMEX NG L1D	Henry Hub			
5/1/2016	11/5/2013	Financial Option	3227413	Call	NYMEX NG L1D	Henry Hub			
5/1/2016	11/5/2013	Financial Option	3227413	Put	NYMEX NG L1D	Henry Hub			
6/1/2016	11/5/2013	Financial Option	3227413	Call	NYMEX NG L1D	Henry Hub			
6/1/2016	11/5/2013	Financial Option	3227413	Put	NYMEX NG L1D	Henry Hub			
7/1/2016	11/5/2013	Financial Option	3227413	Call	NYMEX NG L1D	Henry Hub			
7/1/2016	11/5/2013	Financial Option	3227413	Put	NYMEX NG L1D	Henry Hub			
4/1/2016	12/11/2013	Financial Option	3227513	Call	NYMEX NG L1D	Henry Hub			
4/1/2016	12/11/2013	Financial Option	3227513	Put	NYMEX NG L1D	Henry Hub			
5/1/2016	12/11/2013	Financial Option	3227513	Call	NYMEX NG L1D	Henry Hub			
5/1/2016	12/11/2013	Financial Option	3227513	Put	NYMEX NG L1D	Henry Hub			
6/1/2016	12/11/2013	Financial Option	3227513	Call	NYMEX NG L1D	Henry Hub			
6/1/2016	12/11/2013	Financial Option	3227513	Put	NYMEX NG L1D	Henry Hub			
7/1/2016	12/11/2013	Financial Option	3227513	Call	NYMEX NG L1D	Henry Hub			
7/1/2016	12/11/2013	Financial Option	3227513	Put	NYMEX NG L1D	Henry Hub			
4/1/2016	1/29/2014	Financial Option	3227514	Call	NYMEX NG L1D	Henry Hub			
4/1/2016	1/29/2014	Financial Option	3227514	Put	NYMEX NG L1D	Henry Hub			
5/1/2016	1/29/2014	Financial Option	3227514	Call	NYMEX NG L1D	Henry Hub			
5/1/2016	1/29/2014	Financial Option	3227514	Put	NYMEX NG L1D	Henry Hub			
6/1/2016	1/29/2014	Financial Option	3227514	Call	NYMEX NG L1D	Henry Hub			
6/1/2016	1/29/2014	Financial Option	3227514	Put	NYMEX NG L1D	Henry Hub			
7/1/2016	1/29/2014	Financial Option	3227514	Call	NYMEX NG L1D	Henry Hub			
7/1/2016	1/29/2014	Financial Option	3227514	Put	NYMEX NG L1D	Henry Hub			
4/1/2016	2/10/2014	Financial Option	3227515	Call	IFERC	Transco Zone 4			
4/1/2016	2/10/2014	Financial Option	3227515	Put	IFERC	Transco Zone 4			
5/1/2016	2/10/2014	Financial Option	3227515	Call	IFERC	Transco Zone 4			
5/1/2016	2/10/2014	Financial Option	3227515	Put	IFERC	Transco Zone 4			
6/1/2016	2/10/2014	Financial Option	3227515	Call	IFERC	Transco Zone 4			
6/1/2016	2/10/2014	Financial Option	3227515	Put	IFERC	Transco Zone 4			
7/1/2016	2/10/2014	Financial Option	3227515	Call	IFERC	Transco Zone 4			
7/1/2016	2/10/2014	Financial Option	3227515	Put	IFERC	Transco Zone 4			
4/1/2016	3/3/2014	Financial Option	3227516	Call	IFERC	Transco Zone 4			
4/1/2016	3/3/2014	Financial Option	3227516	Put	IFERC	Transco Zone 4			
5/1/2016	3/3/2014	Financial Option	3227516	Call	IFERC	Transco Zone 4			
5/1/2016	3/3/2014	Financial Option	3227516	Put	IFERC	Transco Zone 4			
6/1/2016	3/3/2014	Financial Option	3227516	Call	IFERC	Transco Zone 4			
6/1/2016	3/3/2014	Financial Option	3227516	Put	IFERC	Transco Zone 4			
7/1/2016	3/3/2014	Financial Option	3227516	Call	IFERC	Transco Zone 4			
7/1/2016	3/3/2014	Financial Option	3227516	Put	IFERC	Transco Zone 4			
4/1/2016	4/9/2014	Financial Option	3227517	Call	IFERC	Henry Hub			
4/1/2016	4/9/2014	Financial Option	3227517	Put	IFERC	Henry Hub			
5/1/2016	4/9/2014	Financial Option	3227517	Call	IFERC	Henry Hub			
5/1/2016	4/9/2014	Financial Option	3227517	Put	IFERC	Henry Hub			
6/1/2016	4/9/2014	Financial Option	3227517	Call	IFERC	Henry Hub			
6/1/2016	4/9/2014	Financial Option	3227517	Put	IFERC	Henry Hub			
7/1/2016	4/9/2014	Financial Option	3227517	Call	IFERC	Henry Hub			
7/1/2016	4/9/2014	Financial Option	3227517	Put	IFERC	Henry Hub			
4/1/2016	5/19/2014	Financial Option	3227520	Call	IFERC	Henry Hub			
4/1/2016	5/19/2014	Financial Option	3227520	Put	IFERC	Henry Hub			
5/1/2016	5/19/2014	Financial Option	3227520	Call	IFERC	Henry Hub			
5/1/2016	5/19/2014	Financial Option	3227520	Put	IFERC	Henry Hub			
6/1/2016	5/19/2014	Financial Option	3227520	Call	IFERC	Henry Hub			
6/1/2016	5/19/2014	Financial Option	3227520	Put	IFERC	Henry Hub			
7/1/2016	5/19/2014	Financial Option	3227520	Call	IFERC	Henry Hub			
7/1/2016	5/19/2014	Financial Option	3227520	Put	IFERC	Henry Hub			
4/1/2016	6/10/2014	Financial Option	3227522	Call	IFERC	Henry Hub			
4/1/2016	6/10/2014	Financial Option	3227522	Put	IFERC	Henry Hub			
5/1/2016	6/10/2014	Financial Option	3227522	Call	IFERC	Henry Hub			
5/1/2016	6/10/2014	Financial Option	3227522	Put	IFERC	Henry Hub			
6/1/2016	6/10/2014	Financial Option	3227522	Call	IFERC	Henry Hub			
6/1/2016	6/10/2014	Financial Option	3227522	Put	IFERC	Henry Hub			
7/1/2016	6/10/2014	Financial Option	3227522	Call	IFERC	Henry Hub			
7/1/2016	6/10/2014	Financial Option	3227522	Put	IFERC	Henry Hub			
4/1/2016	7/21/2014	Financial Option	3238364	Call	IFERC	Henry Hub			
4/1/2016	7/21/2014	Financial Option	3238364	Put	IFERC	Henry Hub			
5/1/2016	7/21/2014	Financial Option	3238364	Call	IFERC	Henry Hub			
5/1/2016	7/21/2014	Financial Option	3238364	Put	IFERC	Henry Hub			
6/1/2016	7/21/2014	Financial Option	3238364	Call	IFERC	Henry Hub			
6/1/2016	7/21/2014	Financial Option	3238364	Put	IFERC	Henry Hub			
7/1/2016	7/21/2014	Financial Option	3238364	Call	IFERC	Henry Hub			
7/1/2016	7/21/2014	Financial Option	3238364	Put	IFERC	Henry Hub			
4/1/2016	8/20/2014	Financial Option	3246476	Call	NYMEX NG L1D	Henry Hub			
4/1/2016	8/20/2014	Financial Option	3246476	Put	NYMEX NG L1D	Henry Hub			
5/1/2016	8/20/2014	Financial Option	3246476	Call	NYMEX NG L1D	Henry Hub			
5/1/2016	8/20/2014	Financial Option	3246476	Put	NYMEX NG L1D	Henry Hub			
6/1/2016	8/20/2014	Financial Option	3246476	Call	NYMEX NG L1D	Henry Hub			
6/1/2016	8/20/2014	Financial Option	3246476	Put	NYMEX NG L1D	Henry Hub			
7/1/2016	8/20/2014	Financial Option	3246476	Call	NYMEX NG L1D	Henry Hub			
7/1/2016	8/20/2014	Financial Option	3246476	Put	NYMEX NG L1D	Henry Hub			
4/1/2016	9/5/2014	Financial Option	3252181	Call	NYMEX NG L1D	Henry Hub			
4/1/2016	9/5/2014	Financial Option	3252181	Put	NYMEX NG L1D	Henry Hub			
5/1/2016	9/5/2014	Financial Option	3252181	Call	NYMEX NG L1D	Henry Hub			
5/1/2016	9/5/2014	Financial Option	3252181	Put	NYMEX NG L1D	Henry Hub			

Delivery Month	Trade Date	Instrument	Trade Number	Put/Call	Market	Location	Strike Price	Trade Price ($/MMBtu)	Settled Quantity MMBtu
6/1/2016	9/5/2014	Financial Option	3252181	Call	NYMEX NG L1D	Henry Hub			
6/1/2016	9/5/2014	Financial Option	3252181	Put	NYMEX NG L1D	Henry Hub			
7/1/2016	9/5/2014	Financial Option	3252181	Call	NYMEX NG L1D	Henry Hub			
7/1/2016	9/5/2014	Financial Option	3252181	Put	NYMEX NG L1D	Henry Hub			
5/1/2016	10/17/2014	Financial Option	3265423	Call	IFERC	Henry Hub			
5/1/2016	10/17/2014	Financial Option	3265423	Put	IFERC	Henry Hub			
6/1/2016	10/17/2014	Financial Option	3265423	Call	IFERC	Henry Hub			
6/1/2016	10/17/2014	Financial Option	3265423	Put	IFERC	Henry Hub			
7/1/2016	10/17/2014	Financial Option	3265423	Call	IFERC	Henry Hub			
7/1/2016	10/17/2014	Financial Option	3265423	Put	IFERC	Henry Hub			
4/1/2016	11/25/2014	Financial Option	3277474	Call	NYMEX NG L1D	Henry Hub			
4/1/2016	11/25/2014	Financial Option	3277474	Put	NYMEX NG L1D	Henry Hub			
5/1/2016	11/25/2014	Financial Option	3277474	Call	NYMEX NG L1D	Henry Hub			
5/1/2016	11/25/2014	Financial Option	3277474	Put	NYMEX NG L1D	Henry Hub			
6/1/2016	11/25/2014	Financial Option	3277474	Call	NYMEX NG L1D	Henry Hub			
6/1/2016	11/25/2014	Financial Option	3277474	Put	NYMEX NG L1D	Henry Hub			
7/1/2016	11/25/2014	Financial Option	3277474	Call	NYMEX NG L1D	Henry Hub			
7/1/2016	11/25/2014	Financial Option	3277474	Put	NYMEX NG L1D	Henry Hub			
5/1/2016	12/3/2014	Financial Option	3279678	Call	IFERC	Henry Hub			
5/1/2016	12/3/2014	Financial Option	3279678	Put	IFERC	Henry Hub			
6/1/2016	12/3/2014	Financial Option	3279678	Call	IFERC	Henry Hub			
6/1/2016	12/3/2014	Financial Option	3279678	Put	IFERC	Henry Hub			
7/1/2016	12/3/2014	Financial Option	3279678	Call	IFERC	Henry Hub			
7/1/2016	12/3/2014	Financial Option	3279678	Put	IFERC	Henry Hub			
5/1/2016	1/12/2015	Financial Option	3292220	Call	IFERC	Henry Hub			
5/1/2016	1/12/2015	Financial Option	3292220	Put	IFERC	Henry Hub			
6/1/2016	1/12/2015	Financial Option	3292220	Call	IFERC	Henry Hub			
6/1/2016	1/12/2015	Financial Option	3292220	Put	IFERC	Henry Hub			
7/1/2016	1/12/2015	Financial Option	3292220	Call	IFERC	Henry Hub			
7/1/2016	1/12/2015	Financial Option	3292220	Put	IFERC	Henry Hub			
4/1/2016	2/9/2015	Financial Option	3301242	Call	NYMEX NG L1D	Henry Hub			
4/1/2016	2/9/2015	Financial Option	3301242	Put	NYMEX NG L1D	Henry Hub			
5/1/2016	2/9/2015	Financial Option	3301242	Call	NYMEX NG L1D	Henry Hub			
5/1/2016	2/9/2015	Financial Option	3301242	Put	NYMEX NG L1D	Henry Hub			
6/1/2016	2/9/2015	Financial Option	3301242	Call	NYMEX NG L1D	Henry Hub			
6/1/2016	2/9/2015	Financial Option	3301242	Put	NYMEX NG L1D	Henry Hub			
7/1/2016	2/9/2015	Financial Option	3301242	Call	NYMEX NG L1D	Henry Hub			
7/1/2016	2/9/2015	Financial Option	3301242	Put	NYMEX NG L1D	Henry Hub			
4/1/2016	2/17/2015	Financial Option	3304155	Call	NYMEX NG L1D	Henry Hub			
4/1/2016	2/17/2015	Financial Option	3304155	Put	NYMEX NG L1D	Henry Hub			
5/1/2016	2/17/2015	Financial Option	3304155	Call	NYMEX NG L1D	Henry Hub			
5/1/2016	2/17/2015	Financial Option	3304155	Put	NYMEX NG L1D	Henry Hub			
6/1/2016	2/17/2015	Financial Option	3304155	Call	NYMEX NG L1D	Henry Hub			
6/1/2016	2/17/2015	Financial Option	3304155	Put	NYMEX NG L1D	Henry Hub			
7/1/2016	2/17/2015	Financial Option	3304155	Call	NYMEX NG L1D	Henry Hub			
7/1/2016	2/17/2015	Financial Option	3304155	Put	NYMEX NG L1D	Henry Hub			
4/1/2016	3/4/2015	Financial Option	3310402	Call	NYMEX NG L1D	Henry Hub			
4/1/2016	3/4/2015	Financial Option	3310402	Put	NYMEX NG L1D	Henry Hub			
5/1/2016	3/4/2015	Financial Option	3310402	Call	NYMEX NG L1D	Henry Hub			
5/1/2016	3/4/2015	Financial Option	3310402	Put	NYMEX NG L1D	Henry Hub			
6/1/2016	3/4/2015	Financial Option	3310402	Call	NYMEX NG L1D	Henry Hub			
6/1/2016	3/4/2015	Financial Option	3310402	Put	NYMEX NG L1D	Henry Hub			
7/1/2016	3/4/2015	Financial Option	3310402	Call	NYMEX NG L1D	Henry Hub			
7/1/2016	3/4/2015	Financial Option	3310402	Put	NYMEX NG L1D	Henry Hub			
4/1/2016	4/10/2015	Financial Option	3321632	Call	NYMEX NG L1D	Henry Hub			
4/1/2016	4/10/2015	Financial Option	3321632	Put	NYMEX NG L1D	Henry Hub			
5/1/2016	4/10/2015	Financial Option	3321632	Call	NYMEX NG L1D	Henry Hub			
5/1/2016	4/10/2015	Financial Option	3321632	Put	NYMEX NG L1D	Henry Hub			
6/1/2016	4/10/2015	Financial Option	3321632	Call	NYMEX NG L1D	Henry Hub			
6/1/2016	4/10/2015	Financial Option	3321632	Put	NYMEX NG L1D	Henry Hub			
7/1/2016	4/10/2015	Financial Option	3321632	Call	NYMEX NG L1D	Henry Hub			
7/1/2016	4/10/2015	Financial Option	3321632	Put	NYMEX NG L1D	Henry Hub			
4/1/2016	5/6/2015	Financial Option	3325562	Call	NYMEX NG L1D	Henry Hub			
4/1/2016	5/6/2015	Financial Option	3325562	Put	NYMEX NG L1D	Henry Hub			
5/1/2016	5/6/2015	Financial Option	3325562	Call	NYMEX NG L1D	Henry Hub			
5/1/2016	5/6/2015	Financial Option	3325562	Put	NYMEX NG L1D	Henry Hub			
6/1/2016	5/6/2015	Financial Option	3325562	Call	NYMEX NG L1D	Henry Hub			
6/1/2016	5/6/2015	Financial Option	3325562	Put	NYMEX NG L1D	Henry Hub			
7/1/2016	5/6/2015	Financial Option	3325562	Call	NYMEX NG L1D	Henry Hub			
7/1/2016	5/6/2015	Financial Option	3325562	Put	NYMEX NG L1D	Henry Hub			
1/1/2016	5/19/2015	Financial Option	3328129	Call	NYMEX NG L1D	Henry Hub			
1/1/2016	5/19/2015	Financial Option	3328129	Put	NYMEX NG L1D	Henry Hub			
2/1/2016	5/19/2015	Financial Option	3328129	Call	NYMEX NG L1D	Henry Hub			

Delivery Month	Trade Date	Instrument	Trade Number	Put/Call	Market	Location	Strike Price	Trade Price ($/MMBtu)	Settled Quantity MMBtu
2/1/2016	5/19/2015	Financial Option	3328129	Put	NYMEX NG L1D	Henry Hub			
3/1/2016	5/19/2015	Financial Option	3328129	Call	NYMEX NG L1D	Henry Hub			
3/1/2016	5/19/2015	Financial Option	3328129	Put	NYMEX NG L1D	Henry Hub			
1/1/2016	6/2/2015	Financial Option	3331417	Call	NYMEX NG L1D	Henry Hub			
1/1/2016	6/2/2015	Financial Option	3331417	Put	NYMEX NG L1D	Henry Hub			
2/1/2016	6/2/2015	Financial Option	3331417	Call	NYMEX NG L1D	Henry Hub			
2/1/2016	6/2/2015	Financial Option	3331417	Put	NYMEX NG L1D	Henry Hub			
3/1/2016	6/2/2015	Financial Option	3331417	Call	NYMEX NG L1D	Henry Hub			
3/1/2016	6/2/2015	Financial Option	3331417	Put	NYMEX NG L1D	Henry Hub			
4/1/2016	6/2/2015	Financial Option	3331417	Call	NYMEX NG L1D	Henry Hub			
4/1/2016	6/2/2015	Financial Option	3331417	Put	NYMEX NG L1D	Henry Hub			
5/1/2016	6/2/2015	Financial Option	3331417	Call	NYMEX NG L1D	Henry Hub			
5/1/2016	6/2/2015	Financial Option	3331417	Put	NYMEX NG L1D	Henry Hub			
6/1/2016	6/2/2015	Financial Option	3331417	Call	NYMEX NG L1D	Henry Hub			
6/1/2016	6/2/2015	Financial Option	3331417	Put	NYMEX NG L1D	Henry Hub			
7/1/2016	6/2/2015	Financial Option	3331417	Call	NYMEX NG L1D	Henry Hub			
7/1/2016	6/2/2015	Financial Option	3331417	Put	NYMEX NG L1D	Henry Hub			
1/1/2016	7/14/2015	Financial Option	3339455	Call	IFERC	Henry Hub			
1/1/2016	7/14/2015	Financial Option	3339455	Put	IFERC	Henry Hub			
2/1/2016	7/14/2015	Financial Option	3339455	Call	IFERC	Henry Hub			
2/1/2016	7/14/2015	Financial Option	3339455	Put	IFERC	Henry Hub			
3/1/2016	7/14/2015	Financial Option	3339455	Call	IFERC	Henry Hub			
3/1/2016	7/14/2015	Financial Option	3339455	Put	IFERC	Henry Hub			
4/1/2016	7/14/2015	Financial Option	3339455	Call	IFERC	Henry Hub			
4/1/2016	7/14/2015	Financial Option	3339455	Put	IFERC	Henry Hub			
5/1/2016	7/14/2015	Financial Option	3339455	Call	IFERC	Henry Hub			
5/1/2016	7/14/2015	Financial Option	3339455	Put	IFERC	Henry Hub			
6/1/2016	7/14/2015	Financial Option	3339455	Call	IFERC	Henry Hub			
6/1/2016	7/14/2015	Financial Option	3339455	Put	IFERC	Henry Hub			
7/1/2016	7/14/2015	Financial Option	3339455	Call	IFERC	Henry Hub			
7/1/2016	7/14/2015	Financial Option	3339455	Put	IFERC	Henry Hub			
1/1/2016	8/5/2015	Financial Option	3344766	Call	IFERC	Transco Zone 4			
1/1/2016	8/5/2015	Financial Option	3344766	Put	IFERC	Transco Zone 4			
2/1/2016	8/5/2015	Financial Option	3344766	Call	IFERC	Transco Zone 4			
2/1/2016	8/5/2015	Financial Option	3344766	Put	IFERC	Transco Zone 4			
3/1/2016	8/5/2015	Financial Option	3344766	Call	IFERC	Transco Zone 4			
3/1/2016	8/5/2015	Financial Option	3344766	Put	IFERC	Transco Zone 4			
4/1/2016	8/5/2015	Financial Option	3344766	Call	IFERC	Transco Zone 4			
4/1/2016	8/5/2015	Financial Option	3344766	Put	IFERC	Transco Zone 4			
5/1/2016	8/5/2015	Financial Option	3344766	Call	IFERC	Transco Zone 4			
5/1/2016	8/5/2015	Financial Option	3344766	Put	IFERC	Transco Zone 4			
6/1/2016	8/5/2015	Financial Option	3344766	Call	IFERC	Transco Zone 4			
6/1/2016	8/5/2015	Financial Option	3344766	Put	IFERC	Transco Zone 4			
7/1/2016	8/5/2015	Financial Option	3344766	Call	IFERC	Transco Zone 4			
7/1/2016	8/5/2015	Financial Option	3344766	Put	IFERC	Transco Zone 4			
1/1/2016	8/18/2015	Financial Option	3347636	Call	NYMEX NG L1D	Henry Hub			
1/1/2016	8/18/2015	Financial Option	3347636	Put	NYMEX NG L1D	Henry Hub			
2/1/2016	8/18/2015	Financial Option	3347636	Call	NYMEX NG L1D	Henry Hub			
2/1/2016	8/18/2015	Financial Option	3347636	Put	NYMEX NG L1D	Henry Hub			
3/1/2016	8/18/2015	Financial Option	3347636	Call	NYMEX NG L1D	Henry Hub			
3/1/2016	8/18/2015	Financial Option	3347636	Put	NYMEX NG L1D	Henry Hub			
1/1/2016	8/21/2015	Financial Option	3348334	Call	NYMEX NG L1D	Henry Hub			
1/1/2016	8/21/2015	Financial Option	3348334	Put	NYMEX NG L1D	Henry Hub			
2/1/2016	8/21/2015	Financial Option	3348334	Call	NYMEX NG L1D	Henry Hub			
2/1/2016	8/21/2015	Financial Option	3348334	Put	NYMEX NG L1D	Henry Hub			
3/1/2016	8/21/2015	Financial Option	3348334	Call	NYMEX NG L1D	Henry Hub			
3/1/2016	8/21/2015	Financial Option	3348334	Put	NYMEX NG L1D	Henry Hub			
1/1/2016	9/9/2015	Financial Option	3352226	Call	NYMEX NG L1D	Henry Hub			
1/1/2016	9/9/2015	Financial Option	3352226	Put	NYMEX NG L1D	Henry Hub			
2/1/2016	9/9/2015	Financial Option	3352226	Call	NYMEX NG L1D	Henry Hub			
2/1/2016	9/9/2015	Financial Option	3352226	Put	NYMEX NG L1D	Henry Hub			
3/1/2016	9/9/2015	Financial Option	3352226	Call	NYMEX NG L1D	Henry Hub			
3/1/2016	9/9/2015	Financial Option	3352226	Put	NYMEX NG L1D	Henry Hub			
1/1/2016	9/18/2015	Financial Option	3354168	Call	NYMEX NG L1D	Henry Hub			
1/1/2016	9/18/2015	Financial Option	3354168	Put	NYMEX NG L1D	Henry Hub			
2/1/2016	9/18/2015	Financial Option	3354168	Call	NYMEX NG L1D	Henry Hub			
2/1/2016	9/18/2015	Financial Option	3354168	Put	NYMEX NG L1D	Henry Hub			
3/1/2016	9/18/2015	Financial Option	3354168	Call	NYMEX NG L1D	Henry Hub			
3/1/2016	9/18/2015	Financial Option	3354168	Put	NYMEX NG L1D	Henry Hub			
4/1/2016	12/15/2015	Financial Option	3370774	Call	NYMEX NG L1D	Henry Hub			
4/1/2016	12/15/2015	Financial Option	3370774	Put	NYMEX NG L1D	Henry Hub			
5/1/2016	12/15/2015	Financial Option	3370774	Call	NYMEX NG L1D	Henry Hub			
5/1/2016	12/15/2015	Financial Option	3370774	Put	NYMEX NG L1D	Henry Hub			
6/1/2016	12/15/2015	Financial Option	3370774	Call	NYMEX NG L1D	Henry Hub			
6/1/2016	12/15/2015	Financial Option	3370774	Put	NYMEX NG L1D	Henry Hub			
7/1/2016	12/15/2015	Financial Option	3370774	Call	NYMEX NG L1D	Henry Hub			
7/1/2016	12/15/2015	Financial Option	3370774	Put	NYMEX NG L1D	Henry Hub			
6/1/2016	3/30/2016	Financial Option	3389346	Call	NYMEX NG L1D	Henry Hub			
6/1/2016	3/30/2016	Financial Option	3389346	Put	NYMEX NG L1D	Henry Hub			
7/1/2016	3/30/2016	Financial Option	3389346	Call	NYMEX NG L1D	Henry Hub			
7/1/2016	3/30/2016	Financial Option	3389346	Put	NYMEX NG L1D	Henry Hub			
5/1/2016	4/5/2016	Financial Option	3390265	Call	NYMEX NG L1D	Henry Hub			
5/1/2016	4/5/2016	Financial Option	3390265	Put	NYMEX NG L1D	Henry Hub			
6/1/2016	4/5/2016	Financial Option	3390265	Call	NYMEX NG L1D	Henry Hub			
6/1/2016	4/5/2016	Financial Option	3390265	Put	NYMEX NG L1D	Henry Hub			
7/1/2016	4/5/2016	Financial Option	3390265	Call	NYMEX NG L1D	Henry Hub			
7/1/2016	4/5/2016	Financial Option	3390265	Put	NYMEX NG L1D	Henry Hub			

* No observable market indications or quotes available for options.

AFFIDAVIT

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

I hereby certify that on this 28 day of September, 2016, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **JOSEPH MCCALLISTER**, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 24, 25, 26, 27, 28, 29, and 30 from STAFF'S SIXTH SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 24-30) in Docket No. 160001-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 28 day of September, 2016.

JOSEPH MCCALLISTER

Katie Jamieson

Notary Public
State of North Carolina

KATIE JAMIESON
Notary Public, North Carolina
Gaston County
My Commission Expires

My Commission Expires:

June 14, 2021

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DEF's Response to Staff's Sixth Set of Interrogatories, Nos. 24-27 (Confidential DN 07860-16)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 84
PARTY: STAFF – (DIRECT)
DESCRIPTION: Joseph McCallister

85

DEF's Response to Staff's Seventh Set of Interrogatories, No. 31

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 85
PARTY: STAFF – (DIRECT)
DESCRIPTION: Marcia Olivier

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor	Docket No. 160001-EI Dated: October 19, 2016

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO STAFF'S SEVENTH SET OF INTERROGATORIES (NO. 31)

Duke Energy Florida, LLC ("DEF"), responds to Staff's Seventh Set of Interrogatories to DEF (No. 31) as follows:

INTERROGATORIES

31. Please refer to page 4 of the testimony of Marcia Olivier filed September 1, 2016 in Docket No. 160001-EI, lines 12 through 23. Also refer to DEF's responses to staff's first data request, # 2, in Docket No. 160151-EI.

a. In the response to the data request, DEF estimates $25.1 million system ($21.1 million retail) for DOE awards. How did DEF estimate this amount?

Response:

DEF's current claim amount is $24.8 million and includes costs from 2011-2013. Although DEF is claiming $24.8 million, the government is asserting various defenses and recovery of the full amount claimed is not guaranteed. The following is the calculation of the retail share. First, the CR3 co-owner portion of 8.2194% is removed, and then the remaining amount is allocated to retail

customers using a separation factor of 92.885% based on Exhibit 1 to the Revised and Restated Stipulation and Settlement Agreement approved in Order No. PSC-13-0598-FOF-EI.

Total Claim	$24.8
Less Co-Owner Share (8.2194%)	(2.0)
Remaining Retail/Wholesale Share	22.7
Multiply by Retail Separation Factor	92.885%
Retail Share	$21.1

b. Are the estimate referenced above specific to the 2011-2013 claim?

Response:

Yes.

c. Are there estimates of DOE awards included in DEF's calculation of 2017 fuel or capacity factors? Please explain.

Response:

No, DEF currently expects to receive the DOE award for the 2011-2013 claim by mid-2018. Therefore, DEF has not included an award in its 2017 fuel or capacity factors.

d. Describe additional claims DEF will pursue regarding spent nuclear fuel.

Response:

DEF currently expects to file its next claim shortly after conclusion of the 2011-2013 claim approximately in mid-2018. DEF currently expects that the next claim will include all of the remaining ISFSI construction costs from 2014 through early 2018. The next claim will also include spent fuel management costs currently being funded through the nuclear decommissioning trust. Any awards from the next claim associated with the construction of the ISFSI will be credited to customers through the Capacity Clause and any awards associated with spent fuel management costs will be credited back to the nuclear decommissioning trust.

160001 Hearing Exhibits 00057

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 19th day of October, 2016, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **MARCIA OLIVIER**, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory number 31 from STAFF'S SEVENTH SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NO. 31) in Docket No. 160001-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 19th day of October, 2016.

Marcia Olivier

Marcia Olivier

Sarah Hirschman Libes
NOTARY PUBLIC
STATE OF FLORIDA
Comm# FF105231
Expires 3/23/2018

Notary Public
State of Florida

My Commission Expires:

3/23/2018

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FPL's Response to Staff's First Set of Interrogatories, Nos. 12 (Redacted), 13, 14, 24 and 25 (Redacted)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 86
PARTY: STAFF – (DIRECT)
DESCRIPTION: Gerard J. Yupp

Q.

For interrogatories 12 through 14, please refer to specific portions of the Direct Testimony of Gerard J. Yupp, filed on March 2, 2016.

Please refer to page 4 of the Direct Testimony of Gerard J. Yupp, filed on March 2, 2016. Provide an explanation and details for the Asset Management Agreement referenced in line 22.

A.

The Asset Management Agreement (AMA) referenced in witness Yupp's testimony, filed on March 2, 2016, consisted of five separate agreements. For each of them, FPL analyzed the appropriate structure of the AMA by evaluating the volume and location of its existing (longer-term) natural gas purchases versus its overall projected natural gas consumption under varying scenarios, to determine the optimal level of upstream capacity that could be released and the optimal number of instances that the capacity could be recalled in order to obtain the greatest level of benefits for customers. While the opportunity for this type of sale is limited due to FPL's high utilization of its firm natural gas transportation, FPL was able to structure the AMA to deliver value to FPL's customers while maintaining the reliability of natural gas supply. The revenues received from the replacement shipper benefitted customers by reducing overall natural gas expenses.

Details of these five agreements are listed below:

1) Agreement #1 [redacted]

2) Agreement #2 [redacted]

3) Agreement #3 [redacted]

4) Agreement #4 [redacted]

5) Agreement #5 [redacted]

These five agreements produced customer savings in 2015 as listed in Column 7 of Exhibit GJY-1, attached to the Direct Testimony of Gerard J. Yupp, filed on March 2, 2016.

Q.

For interrogatories 12 through 14, please refer to specific portions of the Direct Testimony of Gerard J. Yupp, filed on March 2, 2016.

Please refer to pages 5 and 6 of the Direct Testimony of Gerard J. Yupp, filed on March 2, 2016, and also to Schedule A6 in the A Schedules for January and February 2015 to answer the following:
a. For the January A6, what are the underlying reasons/market conditions for the gains on lines 16 and 28 for the transactions with Cargill Power Market, LLC and Southern Company Services, Inc., respectively?

b. For the February A6, what are the underlying reasons/market conditions for the gains on lines 16, 19, 31, and 33 for the transactions with Cargill Power Markets, LLC, Exelon Generating Company, LLC, Tennessee Valley Authority, and PJM Interconnection, LLC, respectively?

A.

a. The gains for Cargill Power Markets, LLC were driven by two factors: the lingering effects of extremely cold weather in the winter of 2014 and sporadic, short-term cold weather in January of 2015. Several months after the winter of 2014, FPL executed economy power sales transactions with Cargill for January 2015 as forward market power prices in the southeast for the winter of 2015 continued to be supported by the extremely cold weather that had occurred in January and February of 2014. From a volume perspective, these forward market transactions contributed roughly 69% of the MWh that FPL sold to Cargill in January 2015. The remaining volume that FPL sold to Cargill was predominately executed on a day-ahead basis during several, short-term periods of cold weather in the southeast that occurred during January 2015.

   The gains for Southern Company Services, Inc. were primarily driven by the previously mentioned short-term periods of cold weather that occurred in January 2015. The economy power sales to Southern Company were primarily day-ahead transactions executed during these colder weather periods.

   Overall, the ultimate level of gains are driven by numerous factors, including market conditions, the availability of excess generation on FPL's system, FPL's cost of generation (factors include fuel prices, FPL's system conditions, and the specific days/hours of the transactions) and transmission availability.

b. Similar to January 2015, the gains for Cargill and Exelon in February 2015 were partially driven by monthly transactions that were executed several months after the winter of 2014 as forward prices continued to be supported by the extremely cold winter of 2014. These transactions contributed roughly 50% and 23% of the total volume that was sold to Cargill and Exelon, respectively, in February 2015. Several periods of cold weather in the southeast during the month also led to strong day-ahead sales to Cargill, Exelon and the Tennessee Valley Authority which helped drive the substantial gains for all three counterparties. Similar periods of cold weather within the territories served by PJM drove prices in that region, at times, substantially higher than FPL's marginal cost of generation which created multiple opportunities for FPL to deliver excess power into PJM.

Q.

For interrogatories 12 through 14, please refer to specific portions of the Direct Testimony of Gerard J. Yupp, filed on March 2, 2016.

Please refer to pages 5 and 6 of the Direct Testimony of Gerard J. Yupp, filed on March 2, 2016, and also to Schedule A9 in the A Schedules for June 2015.
a. What are the underlying reasons/market conditions for the stated savings on line 12 for the transaction with Exelon Generating Company, LLC?

b. What FPL units decreased generation based on this transaction?

c. Did FPL have a partial or full plant outage at the time of this purchase? If yes, please explain.

A.

a. The savings associated with economy purchases from Exelon Generating Company, LLC on Schedule A9 for the month of June 2015 reflect the aggregated amount of multiple transactions. Increased demand, driven by warm weather, created opportunities for FPL to purchase power from the market at a lower cost than its own generation, particularly across the peak hours each day. As shown on Schedule A9, FPL's marginal generation cost averaged $90.76/MWh for the Exelon purchases, reflecting less efficient, oil burning and/or peaking units. Economy purchases from Exelon averaged nearly $40/MWh lower than FPL's cost of generation, resulting in significant customer savings.
b. As described in response to Part a., FPL's less efficient, oil burning and/or peaking units would have decreased generation based on the average marginal cost associated with these purchases.
c. FPL had one partial forced and one full forced outage lasting more than one full day during the month of June 2015. SJRPP Unit No. 2 experienced a partial forced outage due to a circulating water pump motor failure beginning on June 23, 2015 and extending for the duration of the month. This partial forced outage resulted in a 118 MW curtailment of FPL's portion of the unit for the duration of the event. Martin Unit No. 2 (conventional oil/gas fired unit) experienced a full forced outage beginning on the evening on June 21, 2015 that lasted until the mid-afternoon of June 25, 2015. This outage was related to a bearing issue on the unit and resulted in a 788 MW loss for the duration of the event.

Q.

Please refer to Page 2 of Exhibit GJY-1, exhibit attached to the Direct Testimony of Gerard J. Yupp (Wholesale Power Detail) to answer the following:
a. In Table 1, column 10, what are the Power Option Premiums? Please provide a detailed, complete explanation of these options including the risks associated with this type of transaction.

b. What is the specific authority for including these transactions in the incentive mechanism?

A.

a. The Power Option Premiums shown in Column 10 of Table 1 represent payments made to FPL by various counterparties for short-term, Contingency Reserves transactions. Under these transactions, FPL agrees to provide the Buyer's allocation (or a portion of the Buyer's allocation) of Contingency Reserves to the Florida Reserve Sharing Group, when requested. Contingency Reserves are defined as energy that must be fully available within 15 minutes and not restricted by any transmission limitation. In exchange, the Buyer agrees to pay FPL an option premium. FPL will only sell Contingency Reserves to participants within the Florida Reserve Sharing Group. FPL is obligated to deliver Contingency Reserves to the Buyer once a transaction is executed and therefore, the risk associated with these transactions is FPL's ability to deliver energy when necessary, solely from available electric resources or interruptible load. This risk is addressed through a formalized process under which FPL's ability to provide Contingency Reserves is determined solely by the System Operations group after taking into account factors such as load and unit availability.
b. The sale of Contingency Reserves is a form of optimization within the broader category of short-term wholesale sales that provides benefits to FPL's customers. Therefore, FPL includes the option premiums it receives for these transactions as part of its total Incentive Mechanism gains, as approved in Order No. PSC-13-0023-S-EI.

Q.

Please refer to Page 3 of Exhibit GJY-1, exhibit attached to the Direct Testimony of Gerard J. Yupp (Asset Optimization Detail) to answer the following:
a. Please describe the activities for column 5 – Natural Gas Option Premiums.

b. Please describe the activities for column 6 – Natural Gas Storage Options.

A.

a. FPL's natural gas procurement strategy utilizes a mixture of term, month-ahead and daily gas purchases. Given the size of FPL's natural gas portfolio, procurement must be spread across these three categories to ensure that a reliable supply, in sufficient quantities to match demand, is delivered each day. When determining the appropriate amount of volume to purchase within each category, FPL takes into account numerous factors, including projected consumption (including maximum and minimum daily consumption projections), seasonality, market liquidity, and operational constraints. There is a certain amount of price risk inherent in FPL's procurement strategy because of the unpredictable relationship among term, monthly and daily settlement prices. [redacted]

[redacted]

b. FPL primarily utilizes its natural gas storage capacity to ensure the reliability of supply and to help manage the daily consumption "swings" due to weather and unit availability changes. However given the dynamic nature of the natural gas market and occasional pricing imbalances, FPL is also able to optimize idle storage capacity, when available.

FPL's optimization strategy for gas storage is focused on capturing price differences in the forward curve. Natural gas prices are volatile and highly seasonal with prices exhibiting contango and backwardation at different points in time. Contango describes a market where spot prices are lower than future prices. Backwardation describes a market where spot prices are higher than future prices. These market conditions present the opportunity for optimization, if the following conditions exist for FPL:

1) The price spread between the lowest price and the highest price on the forward curve is sufficient to cover fuel and variable costs associated with utilizing storage capacity.
2) FPL is confident that it will not require the volume of storage being optimized for the term of the transaction.
3) Sufficient liquidity is present in the market to ensure that FPL can execute both sides of the transaction simultaneously. FPL must always execute each side of the transaction to lock in the gain.

DECLARATION

I sponsored the answers to Interrogatory Nos. 1 through 14 and 24 through 25 from **STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-25)** to Florida Power & Light Company in Docket No. 160001-EI, and that 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: 4/21/16

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FPL's Response to Staff's First Set of Interrogatories, Nos. 12 and 25 (Confidential DN 02405-16)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 87
PARTY: STAFF – (DIRECT)
DESCRIPTION: Gerard J. Yupp

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FPL's Response to Staff's Second Set of Interrogatories, Nos. 26-29

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 88
PARTY: STAFF – (DIRECT)
DESCRIPTION: Charles R. Rote

Q.

For interrogatories 26 through 29, please refer to page 3 of 19 from Exhibit CRR-1, attached to the Direct Testimony of Charles R. Rote, filed on March 16, 2016. The end of month Common Equity balance amount of $13,850,484,435 for January 2015 (Line 2) will be used as a common reference in many of these questions.

Is the end of month Common Equity balance amount of $13,850,484,435 for January 2015 (Line 2) a system amount or a jurisdictional amount? Explain in your response why a system (or a jurisdictional) amount is appropriate for the purpose of calculating GPIF rewards and penalties.

A.

It is a system amount. The GPIF Implementation Manual Sheet No. 3.504 (Estimate) and Sheet No. 3.516 (Actual) provides the steps to calculate the appropriate jurisdictional amount for calculating the maximum allowed reward and penalty. FPL appropriately followed these steps as shown on Exhibit CCR-1, page 3, attached to the direct testimony of Charles R. Rote file on March 16, 2016.

Q.

For interrogatories 26 through 29, please refer to page 3 of 19 from Exhibit CRR-1, attached to the Direct Testimony of Charles R. Rote, filed on March 16, 2016. The end of month Common Equity balance amount of $13,850,484,435 for January 2015 (Line 2) will be used as a common reference in many of these questions.

Please identify the specific source for the end of month Common Equity balance amount of $13,850,484,435 for January 2015 (Line 2 of Page 3 from Exhibit CRR-1). If applicable, describe any and all different sources for February 2015 (Line 3) through December 2015 (Line 13) amounts.

A.

The Common Equity balance amount of $13,850,484,435 for January 2015 (Line 2 of Page 3 from Exhibit CRR-1) and each respective month in the 13 month average calculation is derived from FPL's consolidated balance sheet and is the sum of the following FERC Accounts: 201.000, 201.100, 211.000, 211.700, 214.000 and 216.000.

Q.

For interrogatories 26 through 29, please refer to page 3 of 19 from Exhibit CRR-1, attached to the Direct Testimony of Charles R. Rote, filed on March 16, 2016. The end of month Common Equity balance amount of $13,850,484,435 for January 2015 (Line 2) will be used as a common reference in many of these questions.

Please identify by specific schedule and line where the end of month Common Equity balance amount of $13,850,484,435 for January 2015 (Line 2 on Page 3 of CRR-1) is reported in FPL's Earnings Surveillance Report for the same period. If this amount is not reported in FPL's Earnings Surveillance Report for the same period, please explain why not.

A.

The total company end of month common equity balance amount of $13,850,484,435 for January 2015 is not reported in FPL's Earnings Surveillance Report (ESR) for the same period. Schedule 4.1 in the Earnings Surveillance Report, which details capital structure on both a 13 month average and month ended basis, calculates an adjusted retail capital structure by starting with System Per Book amounts for each class of capital and applying separation factors and commission adjustments to get to adjusted amounts. The System Per Book amounts are calculated by reducing the total company amounts for each class of capital reflected on FPL's general ledger for Non-Utility Property & Other Special Funds. To determine the appropriate total company maximum allowed GPIF reward/penalty using common equity balances, FPL followed the steps in the GPIF Implementation Manual Sheets No. 3.504 (Estimate) and 3.516 (Actual), which do not call for the ESR adjustments.

Q.

For interrogatories 26 through 29, please refer to page 3 of 19 from Exhibit CRR-1, attached to the Direct Testimony of Charles R. Rote, filed on March 16, 2016. The end of month Common Equity balance amount of $13,850,484,435 for January 2015 (Line 2) will be used as a common reference in many of these questions.

For the common equity balance that FPL used to calculate its 2015 GPIF reward, please cite the specific order(s) and authority for using that specific common equity balance.

A.

The common equity balances on Page 3 of CRR-1 were used to calculate the maximum allowed jurisdictional incentive dollars (Line 21), not to calculate directly the actual 2015 GPIF reward. FPL followed the steps specified in the GPIF Implementation Manual Sheets No. 3.504 and 3.516* to develop the estimated and actual maximum allowed jurisdictional incentive dollars. FPL is aware of the following orders issued by the Commission related to GPIF Implementation Manual and the steps involved in the calculation of the maximum allowed jurisdictional incentive dollars.

- Order No. 9558 issued 9/19/80 in Docket No. 800400-CI adopting the initial GPIF Implementation Manual.
- Order No. 10168 issued 7/28/81 in Docket No. 810001-CI adopting revised GPIF Implementation Manual.
- Order No. 10912 issued 6/22/82 in Docket No. 820001-EU (MC) adopting further changes to the GPIF Implementation Manual including revised original Sheet No. 3.504 and 3.516.
- Order No. PSC-13-0665-FOF-EI issued 12/18/13 in Docket No. 130001-EI further revising Sheet No. 3.516 and in effect associated Sheet No. 3.504. FPL and the other Florida IOUs revised Sheet 3.504 to be consistent with the methodology on Sheet 3.516

Please note that the original GPIF Implementation Manual called for utilizing seven months of common equity balances to develop the estimated and actual maximum allowed jurisdictional incentive dollars when the Fuel Clause filing was done every six months. Later on, and concurrent with the Fuel Clause filing timing change from 6 to 12 months, FPL began utilizing 13 months of common equity balances to develop the estimated and actual maximum allowed jurisdictional incentive dollars.

*The latest revised Sheet No. 3.516 (Attachment 1 to this interrogatory response) is as shown in Order PSC-13-0665-FOF-EI. The steps on Sheet No. 3.504 (not shown in the Order) are the same as Sheet 3.516. The difference is that Sheet 3.504 is used for the projection filing with estimated common equity balances while Sheet 3.516 is used for the true-up filing with actual common equity balances.

Original Sheet No. 3.516 as Revised

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY	$	10,849,749,770
LINE 2	MONTH OF January 2012	$	10,983,930,940
LINE 3	MONTH OF February 2012	$	11,043,325,330
LINE 4	MONTH OF March 2012	$	11,128,965,610
LINE 5	MONTH OF April 2012	$	11,196,334,650
LINE 6	MONTH OF May 2012	$	11,333,068,500
LINE 7	MONTH OF June 2012	$	11,681,736,330
LINE 8	MONTH OF July 2012	$	11,828,681,570
LINE 9	MONTH OF August 2012	$	11,987,094,020
LINE 10	MONTH OF September 2012	$	12,073,906,876
LINE 11	MONTH OF October 2012	$	12,172,856,430
LINE 12	MONTH OF November 2012	$	12,463,562,700
LINE 13	MONTH OF December 2012	$	12,530,193,155
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)	$	11,636,415,837
LINE 15	25 BASIS POINTS		0.0025
LINE 16	REVENUE EXPANSION FACTOR		61.3808%
LINE 17	MAXIMUM INCENTIVE DOLLARS PER FINANCIAL DATA (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)	$	47,394,364
LINE 18	JURISDICTIONAL SALES		102,225,549,000 KWH
LINE 19	TOTAL SALES		104,462,720,986 KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		97.86%
LINE 21	MAXIMUM JURISDICTIONAL INCENTIVE DOLLARS (LINE 17 TIMES LINE 20)	$	46,380,125
LINE 22	INCENTIVE CAP (50 PECENT OF PROJECTED FUEL SAVINGS AT 10 GPIF-POINT LEVEL FROM SHEET NO. 3.515)	$	45,541,500
LINE 23	MAXIMUM ALLOWED GPIF REWARD (AT 10 GPIF-POINT LEVEL) (THE LESSER OF LINE 21 AND LINE 22)	$	45,541,500

Issued by: Florida Public Service Commission **Effective 1/1/2014**

DECLARATION

I sponsored the answers to Interrogatory Nos. 26 through 29 from **STAFF'S SECOND SET OF INTERROGATORIES (NOS. 26-29)** to Florida Power & Light Company in Docket No. 160001-EI, and that 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 R. Rote

Date: 5/17/2016

89

FPL's Response to Staff's Fourth Set of Interrogatories, No. 41 (Redacted)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 89
PARTY: STAFF – (DIRECT)
DESCRIPTION: Gerard J. Yupp

Q.

For the purpose of this interrogatory, please complete Table 1 below:

A.

Table 1 includes hedging percentages based on both projected burn volumes (determined prior to the beginning of a month) and actual burn values from FPL's monthly A3 Schedule (determined after the month has ended). The projected fuel burn volumes, calculated by the GenTrader production cost model, are compared to hedging program positions to establish the hedged percentage values. The hedged percentages are then compared to the Risk Management Plan limits to verify hedged volumes are in compliance with the Commission approved Risk Management Plan. Actual fuel burn volumes, which are available only after hedging has been completed and hedging transactions have settled, are not compared to Risk Management Plan target percentage levels since they are not relevant to percentage calculations.

TABLE 1

Monthly Percent of Natural Gas Volume Hedged in Relation to Total Burned

FPL

2013 - 2016

	2013		2014		2015		2016	
	Based on Last Projection	Based on Month-End Actuals	Based on Last Projection	Based on Month-End Actuals	Based on Last Projection	Based on Month-End Actuals	Based on Last Projection	Based on Month-End Actuals
January								
February								
March								
April								
May								
June								
July								
August							N/A	N/A
September							N/A	N/A
October							N/A	N/A
November							N/A	N/A
December							N/A	N/A
Yearly Average							N/A	N/A
Hedging Range for Natural Gas identified in that year's Risk Management Plan								

NOTE: All percentages are based on natural gas financial hedging activity.

DECLARATION

I sponsored the answer to Interrogatory No. 41 from **STAFF'S FOURTH SET OF INTERROGATORIES (NO. 41)** to Florida Power & Light Company in Docket No. 160001-EI, and that 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: 8/19/16

90

FPL's Response to Staff's Fourth Set of Interrogatories, No. 41 (Confidential DN 07038-16)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 90
PARTY: STAFF – (DIRECT)
DESCRIPTION: Gerard J. Yupp

91

FPL's Response to Staff's Fifth Set of Interrogatories, Nos. 42-49

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 91
PARTY: STAFF – (DIRECT)
DESCRIPTION: Gerard J. Yupp

Q.

For the purpose of the following Interrogatory Numbers 42-48, please refer to the following:
A. Attachment B, Components Of A Utility's Fuel Procurement Risk Management Plan, Exhibit TFB-4, attached to Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI ("TFB-4").

B. Florida Power & Light's Risk Management Plan for 2017 filed on August 4, 2016, in Docket No. 160001-EI ("FPL's 2017 Plan").

TFB-4 (sub-part 1) indicates that a Fuel Procurement Risk Management Plan should include information identifying the overall quantitative and qualitative risk management objectives. Please identify by page and line reference(s) where this is addressed in FPL's 2017 Plan.

A.

TFB-4 (sub-part 1) is addressed in FPL's 2017 Plan on page 1, in the section labeled "Overall Quantitative and Qualitative Risk Management Objectives (TFB-4, Item 1)".

Q.

For the purpose of the following Interrogatory Numbers 42-48, please refer to the following:
A. Attachment B, Components Of A Utility's Fuel Procurement Risk Management Plan, Exhibit TFB-4, attached to Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI ("TFB-4").

B. Florida Power & Light's Risk Management Plan for 2017, filed on August 4, 2016, in Docket No. 160001-EI ("FPL's 2017 Plan").

TFB-4 (sub-part 2) indicates that a Fuel Procurement Risk Management Plan should include information regarding identifying the minimum quantity of fuel to be hedged. Please identify by page and line reference(s) where this is addressed in FPL's 2017 Plan.

A.

TFB-4 (sub-part 2) is addressed in FPL's 2017 Plan on page 5, in the section labeled "2017 Hedging Strategy (TFB-4, Items 2 and 8)". FPL's hedging strategy detail is also included in the Planned Position Strategy (PPS) documents included as part of FPL's 2017 Plan.

Q.

For the purpose of the following Interrogatory Numbers 42-48, please refer to the following:
A. Attachment B, Components Of A Utility's Fuel Procurement Risk Management Plan, Exhibit TFB-4, attached to Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI ("TFB-4").

B. Florida Power & Light's Risk Management Plan for 2017 filed on August 4, 2016, in Docket No. 160001-EI ("FPL's 2017 Plan").

TFB-4 (sub-part 3) indicates that a Fuel Procurement Risk Management Plan should include information identifying and quantifying the general and specific risks a utility may encounter with its fuel procurement. Please identify by page and line reference(s) where this is addressed in FPL's 2017 Plan.

A.

TFB-4 (sub-part 3) is addressed in FPL's 2017 Plan on pages 1-3, in the section labeled "Fuel Procurement Risks (TFB-4, Item 3)."

Q.

For the purpose of the following Interrogatory Numbers 42-48, please refer to the following:
A. Attachment B, Components Of A Utility's Fuel Procurement Risk Management Plan, Exhibit TFB-4, attached to Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI ("TFB-4").

B. Florida Power & Light's Risk Management Plan for 2017 filed on August 4, 2016, in Docket No. 160001-EI ("FPL's 2017 Plan").

TFB-4 (sub-part 4) indicates that a Fuel Procurement Risk Management Plan should include information describing the oversight of a utility's fuel procurement activities. Please identify by page and line reference(s) where this is addressed in FPL's 2017 Plan.

A.

TFB-4 (sub-part 4) is addressed in FPL's 2017 Plan on pages 3-5, in the section labeled "Fuel Procurement Oversight / Policies and Procedures (TFB-4, Items 4, 5, 6, 7, and 9)." Detailed information regarding FPL's hedging policies and procedures is also included in the Energy Trading and Risk Management Policy and Trading and Risk Management Procedures Manual, both of which have been included as part of FPL's 2017 Plan.

Q.

For the purpose of the following Interrogatory Numbers 42-48, please refer to the following:
A. Attachment B, Components Of A Utility's Fuel Procurement Risk Management Plan, Exhibit TFB-4, attached to Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI ("TFB-4").

B. Florida Power & Light's Risk Management Plan for 2017 filed on August 4, 2016, in Docket No. 160001-EI ("FPL's 2017 Plan").

TFB-4 (sub-part 6) indicates that a Fuel Procurement Risk Management Plan should include information describing the utility's corporate risk policy regarding fuel procurement activities. Please identify by page and line reference(s) where this is addressed in FPL's 2017 Plan.

A.

TFB-4 (sub-part 6) is addressed in FPL's 2017 Plan on pages 3-5, in the section labeled "Fuel Procurement Oversight / Policies and Procedures (TFB-4, Items 4, 5, 6, 7, and 9)."

Q.

For the purpose of the following Interrogatory Numbers 42-48, please refer to the following:
A. Attachment B, Components Of A Utility's Fuel Procurement Risk Management Plan, Exhibit TFB-4, attached to Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI ("TFB-4").

B. Florida Power & Light's Risk Management Plan for 2017 filed on August 4, 2016, in Docket No. 160001-EI ("FPL's 2017 Plan").

TFB-4 (sub-part 8) indicates that a Fuel Procurement Risk Management Plan should describe a utility's strategy to fulfill its risk management objectives. Please identify by page and line reference(s) where this is addressed in FPL's 2017 Plan.

A.

TFB-4 (sub-part 8) is addressed in FPL's 2017 Plan on page 5, in the section labeled "2017 Hedging Strategy (TFB-4, Items 2 and 8)". FPL's hedging strategy detail is also included in the Planned Position Strategy (PPS) documents included as part of FPL's 2017 Plan.

Q.

For the purpose of the following Interrogatory Numbers 42-48, please refer to the following:
A. Attachment B, Components Of A Utility's Fuel Procurement Risk Management Plan, Exhibit TFB-4, attached to Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI ("TFB-4").

B. Florida Power & Light's Risk Management Plan for 2017 filed on August 4, 2016, in Docket No. 160001-EI ("FPL's 2017 Plan").

TFB-4 (sub-part 13) indicates that a Fuel Procurement Risk Management Plan should include information describing a utility's reporting system for fuel procurement activities.

a. Please identify by page and line reference(s) where this is addressed in FPL's 2017 Plan.

b. TFB-4 (sub-part 14) indicates that a utility's reporting system for fuel procurement activities should consistently and comprehensively identify all forms of risk associated with fuel procurement activities. Please state by page and line reference(s) where risk identification within the utility's reporting system is addressed in FPL's 2017 Plan.

c. TFB-4 (sub-part 14) indicates that a utility's reporting system for fuel procurement activities should consistently and comprehensively measure all forms of risk associated with fuel procurement activities. Please state by page and line reference(s) where risk measurement within the utility's reporting system is addressed in FPL's 2017 Plan.

d. TFB-4 (sub-part 14) indicates that a utility's reporting system for fuel procurement activities should consistently and comprehensively monitor all forms of risk associated with fuel procurement activities. Please state by page and line reference(s) where risk monitoring within the utility's reporting system is addressed in FPL's 2017 Plan.

A.

a. TFB-4 (sub-part 13) is addressed in FPL's 2017 Plan on page 6, in the section labeled "Reporting System for Fuel Procurement Activities (TFB-4, Items 13 and 14)".

b. TFB-4 (sub-part 14) is addressed in FPL's 2017 Plan on page 6, in the section labeled "Reporting System for Fuel Procurement Activities (TFB-4, Items 13 and 14)".

c. TFB-4 (sub-part 14) is addressed in FPL's 2017 Plan on page 6, in the section labeled "Reporting System for Fuel Procurement Activities (TFB-4, Items 13 and 14)".

d. TFB-4 (sub-part 14) is addressed in FPL's 2017 Plan on page 6, in the section labeled "Reporting System for Fuel Procurement Activities (TFB-4, Items 13 and 14)".

Q.

Are the processes and practices for hedging natural gas prices that FPL follows the same processes and practices that are followed by any and all unregulated parent or affiliated companies? Discuss in your response how and why the processes and practices for hedging natural gas prices are alike, or different, between FPL, the regulated entity, and any and all unregulated parent or affiliated companies.

A.

FPL is not aware of the natural gas hedging processes, procedures, or practices that are followed by any of its unregulated parent or affiliated companies.

DECLARATION

I sponsored the answers to Interrogatory Nos. 42 through 49 from **STAFF'S FIFTH SET OF INTERROGATORIES (NOS. 42-49)** to Florida Power & Light Company in Docket No. 160001-EI, and that 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: 8/19/16

92

FPL's Response to Staff's Sixth Set of Interrogatories, Nos. 50 (Redacted), 51-55

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 92
PARTY: STAFF – (DIRECT)
DESCRIPTION: Gerard J. Yupp

Q.

For realized (actual) hedging savings and costs for the twelve months beginning August 1, 2015, and ending July 31, 2016, associated with swap contracts for natural gas, please provide the following information in a schedule format:

a. the transaction date (the date the swap was entered into) for the swap;
b. the fixed price for the swap;
c. the month or period in the future the swap is covering; and
d. the corresponding NYMEX futures price for the future month or period for natural gas on the transaction date of the swap.

A.

A schedule of natural gas financial hedging transactions, incorporating the transaction date, fixed price, transaction period, and NYMEX price is included as confidential Attachment I to this response. The forward prices represent the Henry Hub Natural Gas financial swap prices published by NYMEX.

AUGUST 1, 2015 - JULY 31, 2016 HEDGING PROGRAM - NATURAL GAS SWAP TRANSACTIONS

Portfolio A	Trade Date B	Deal Start Date C	Deal End Date D	Fixed Price E	NYMEX Closing Price F	Fixed Price vs NYMEX Price
[redacted]						0.2%
						-1.1%
						-0.1%
						-1.6%
						-0.9%
						-0.5%
						-0.2%
						-0.1%
						-0.2%
						0.1%
						0.1%
						0.3%
						0.3%
						0.7%
						0.3%
						0.5%
						-1.0%
						0.6%
						0.4%
						0.8%
						0.3%
						0.3%
						0.0%
						-0.2%
						1.3%
						0.3%
						0.2%
						-0.5%
						0.5%
						0.5%
						-0.6%
						0.6%
						-0.8%
						-0.1%
						-0.1%
						0.0%
						0.3%
						-0.4%
						0.4%
						0.1%
						0.7%
						0.5%
						0.6%
						0.9%
						-0.2%
						0.6%
						0.2%
						-0.2%
						1.0%
						0.3%
						0.1%
						-0.3%
						0.1%
						0.5%
						0.0%
						0.1%
						-0.2%
						0.3%
						0.6%
						0.0%
						0.2%
						0.3%
						0.0%
						0.4%
						0.3%
						0.0%
						2.4%
						-0.3%

Portfolio A	Trade Date B	Deal Start Date C	Deal End Date D	Fixed Price E	NYMEX Closing Price F	Fixed Price vs NYMEX Price
[redacted]						0.3%
						-0.2%
						0.1%
						-0.3%
						0.1%
						0.6%
						-0.1%
						0.0%
						0.4%
						0.3%
						-1.0%
						-1.7%
						-0.4%
						-0.6%
						-0.1%
						-0.4%
						-0.9%
						-0.5%
						0.2%
						0.0%
						-0.1%
						-0.2%
						-0.7%
						-0.1%
						0.1%
						0.0%
						0.2%
						-0.5%
						-0.3%
						0.1%
						0.0%
						0.0%
						0.6%
						0.0%
						0.2%
						-0.3%
						-0.5%
						0.1%
						-0.1%
						-0.3%
						0.6%
						-0.3%
						0.2%
						0.1%
						0.1%
						-0.5%
						0.8%
						-0.5%
						0.1%
						0.3%
						0.2%
						-0.3%
						-0.4%
						0.0%
						-0.4%
						-0.7%
						0.0%
						0.7%
						0.5%
						0.0%
						0.1%
						-0.8%
						-0.3%
						0.6%
						0.4%
						-0.7%
						0.0%
						-0.1%
						0.0%
						0.2%
						0.3%
						0.3%
						0.1%

Portfolio A	Trade Date B	Deal Start Date C	Deal End Date D	Fixed Price E	NYMEX Closing Price F	Fixed Price vs NYMEX Price
						-0.4%
						1.0%
						0.9%
						0.5%
						-0.8%
						-0.1%
						0.3%
						0.2%
						0.2%
						0.3%
						0.0%
						0.1%
						0.1%
						0.1%
						-1.5%
						-0.5%
						0.9%
						0.2%
						1.9%
						0.0%
						-1.1%
						0.1%
						0.1%
						0.0%
						0.0%
						0.9%
						-0.3%
						-0.2%
						1.2%
						1.2%
						0.6%
						0.7%
						0.1%
						0.1%
						0.3%
						0.1%
						0.0%
						-1.4%
						-1.0%
						-0.4%
						0.0%
						0.7%
						0.4%
						0.2%
						0.1%
						0.0%
						0.0%
						0.0%
						-0.5%
						-0.5%
						0.3%
						0.1%
						-0.1%
						-0.2%
						0.5%
						-1.6%
						-0.8%
						0.3%
						0.3%
						0.2%
						-0.2%
						0.0%
						0.7%
						-0.3%
						-0.1%
						0.3%
						-0.1%
						-0.2%
						-0.2%
						-0.3%
						0.0%
						0.4%
						0.6%

Portfolio A	Trade Date B	Deal Start Date C	Deal End Date D	Fixed Price E	NYMEX Closing Price F	Fixed Price vs NYMEX Price
[redacted]						0.9%
						-0.1%
						0.3%
						0.2%
						0.2%
						1.3%
						1.1%
						0.0%
						-0.1%
						0.5%
						-0.1%
						0.2%
						0.1%
						0.0%
						0.5%
						0.2%
						-0.8%
						-0.3%
						-0.3%
						-2.0%
						-0.7%
						0.1%
						-0.8%
						1.4%
						0.4%
						-0.6%
						0.5%
						0.1%
						0.8%
						0.5%
						-1.2%
						-0.1%
						1.7%
						-0.1%
						0.4%
						0.6%
						0.1%
						0.3%
						0.2%
						0.5%
						-0.2%
						0.4%
						0.3%
						0.1%
						0.3%
						1.6%
						0.7%
						0.1%
						0.9%
						0.4%
						-0.4%
						-0.4%
						0.0%
						0.0%
						0.1%
						0.2%
						0.6%
						-0.5%
						0.2%
						0.5%
						0.4%
						0.5%
						0.0%
						0.3%
						1.1%
						0.0%
						0.1%
						0.5%
						-0.4%
						-0.2%
						-0.3%
						-0.2%
						0.2%

Portfolio A	Trade Date B	Deal Start Date C	Deal End Date D	Fixed Price E	NYMEX Closing Price F	Fixed Price vs NYMEX Price
[redacted]						0.3%
						0.3%
						-0.2%
						-0.6%
						-0.4%
						-0.6%
						-0.1%
						-0.5%
						0.2%
						-0.2%
						-0.1%
						0.1%
						0.0%
						-0.2%
						0.1%
						0.3%
						0.1%
						0.9%
						0.6%
						1.1%
						0.1%
						0.2%
						0.6%
						0.7%
						-1.1%
						-0.1%
						0.3%
						0.9%
						0.2%
						0.7%
						-0.1%
						-1.2%
						-0.2%
						0.0%
						-0.1%
						0.1%
						0.0%
						-1.0%
						-0.4%
						0.5%
						1.6%
						-0.3%
						0.4%
						0.0%
						0.8%
						0.9%
						0.6%
						0.0%
						-0.6%
						0.3%
						0.0%
						-0.4%
						-0.2%
						-0.8%
						0.6%
						-0.2%
						0.2%
						0.1%
						-0.3%
						-0.1%
						0.6%
						-0.1%
						0.2%
						-0.3%
						0.1%
						0.1%
						0.1%
						0.2%
						0.0%
						0.6%
						0.2%
						0.2%
						0.6%

Portfolio A	Trade Date B	Deal Start Date C	Deal End Date D	Fixed Price E	NYMEX Closing Price F	Fixed Price vs NYMEX Price
[redacted]						0.6%
						0.3%
						-1.1%
						-0.2%
						-0.4%
						-0.3%
						-0.1%
						-0.9%
						-0.3%
						0.3%
						-0.3%
						1.2%
						-0.2%
						0.5%
						0.6%
						-0.9%
						0.2%
						-0.1%
						0.1%
						-0.4%
						0.1%
						0.2%
						-1.1%
						-0.5%
						0.3%
						0.2%
						-0.1%
						0.2%
						-0.2%
						0.1%
						-0.2%
						2.1%
						0.0%
						0.2%
						0.0%
						0.2%
						-0.1%
						0.1%
						0.0%
						0.9%
						0.1%
						-0.2%
						0.1%
						-0.5%
						0.0%
						-0.5%
						-0.1%
						-0.9%
						-0.5%
						0.1%
						0.1%
						-0.2%
						-0.1%
						0.2%
						0.3%
						1.6%
						2.2%
						-0.1%
						0.4%
						0.3%
						-0.2%
						-0.7%
						-0.7%
						-0.2%
						-1.3%
						-0.7%
						0.0%
						0.1%
						0.2%
						0.2%
						0.1%
						0.1%
						-0.1%

Portfolio A	Trade Date B	Deal Start Date C	Deal End Date D	Fixed Price E	NYMEX Closing Price F	Fixed Price vs NYMEX Price	
[redacted]						-0.1%	
						-0.2%	
						-0.2%	
						-0.1%	
						-0.1%	
						0.2%	
						0.1%	
						0.7%	
						-0.1%	
						-0.2%	
						0.4%	
						0.3%	
						0.3%	
						-0.8%	
						-0.3%	
						-0.2%	
						-0.2%	
						0.1%	
						0.0%	
						-0.8%	
						0.4%	
						-1.0%	
						-0.8%	
						-1.8%	
						-1.2%	
						-0.3%	
						0.0%	
						0.1%	
						-0.3%	
						0.8%	
						0.8%	
						0.0%	*
						1.0%	*
						0.3%	*
						-1.7%	*

(*) Note: These deals were originally executed as 12-month (January 2015-December 2015) strip transactions. The April-December component was transferred to another counterparty, with the same terms and conditions as originally executed, prior to settlement. The fixed price vs. NYMEX closing price calculations use closing values from the dates on which the transactions were originally executed.

Q.

For interrogatory 50 above, please explain the difference, if any, between the swap fixed price and the corresponding futures or forward price for the future period (the period being hedged) that is greater than 5 percent of the swap fixed price.

A.

The differences between the fixed price and the corresponding NYMEX swap price for all natural gas financial hedge transactions for the period from August 1, 2015 through July 31, 2016 were less than 5 percent of the swap fixed prices. The calculations are included as part of FPL's response to Staff's 6th Set of Interrogatories No. 50.

Q.

For realized (actual) hedging savings and costs for the twelve months beginning August 1, 2015, and ending July 31, 2016, associated with options for natural gas prices, please provide the following information in a schedule format.

a. the transaction date for the option;
b. the option price or premium;
c. the type of option;
d. the time to expiration; and
e. the corresponding futures price, forward price, or comparable market price for the period on the transaction date of the option.

A.

FPL's Hedging/Risk Management plan did not include natural gas option transactions for either 2015 or 2016.

Q.

For interrogatory 52 above, please explain the difference, if any, between the option price and the corresponding futures price, forward price, or comparable market price for the future period (the period being hedged) that is greater than 5 percent of the option price.

A.

FPL's Hedging/Risk Management plan did not include natural gas option transactions for either 2015 or 2016.

Q.

For open hedging transactions since August 1, 2015, has FPL experienced any defaults by a counter-party? If yes, please identify the counter-party and explain.

A.

No. FPL has not experienced any defaults by counterparties since August 1, 2015 for open hedging transactions.

Q.

Does FPL use its firm gas storage for physically hedging the price of natural gas? Please explain your response.

A.

No. FPL does not use its firm gas storage for physically hedging the price of natural gas.

DECLARATION

I sponsored the answers to Interrogatory Nos. 50 through 55 from **STAFF'S SIXTH SET OF INTERROGATORIES (NOS. 50-55)** to Florida Power & Light Company in Docket No. 160001-EI, and that 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: 9/26/16

93

FPL's Response to Staff's Sixth Set of Interrogatories, No. 50 (Confidential DN 07867-16)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 93
PARTY: STAFF – (DIRECT)
DESCRIPTION: Gerard J. Yupp

94

FPL's Response to OPC's Second Request for Production of Document, No. 3

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 94
PARTY: STAFF – (DIRECT)
DESCRIPTION: Gerard J. Yupp

Q.

Please provide copies of the Columbia Gulf Mainline Index as well as the other indexes for the period over which FPL obtained natural gas from the Woodford Project referenced in FPL's response to Interrogatories Nos. 76 and 77.

A.

FPL does not retain copies of the Platts Gas Daily publication in which daily index prices appear for numerous supply locations. FPL utilizes third party data management software named ZEMA to collect and retain daily index prices. The Platts Gas Daily index prices provided in this response as Bates Nos. FCR-16-00033 through FCR-16-00044 were collected via the ZEMA software.

Date	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Carthage Hub**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Columbia Gulf Mainline**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Transco Zone 4**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Sonat LA**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 1**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 2**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 3**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Florida City Gates**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Henry Hub**
March 1, 2015	$2.7000	$2.7050	$2.8250	$2.7450	$2.7000	$2.7800	$2.8200		$2.7700
March 2, 2015	$2.7000	$2.7050	$2.8250	$2.7450	$2.7000	$2.7800	$2.8200		$2.7700
March 3, 2015	$2.8800	$2.8100	$2.9150	$2.8550	$2.8900	$2.8350	$2.9000		$2.8500
March 4, 2015	$2.9550	$2.9200	$3.0200	$2.9450	$2.9750	$2.9800	$3.0150		$2.9450
March 5, 2015	$3.2700	$3.2800	$3.2800	$3.2750	$3.1900	$3.2700	$3.2550	$3.4050	$3.2600
March 6, 2015	$3.1200	$3.2000	$3.3000	$3.2200	$3.2500	$3.2500	$3.2250		$3.2750
March 7, 2015	$2.8100	$2.8300	$2.9150	$2.8850		$2.8650	$2.9100		$2.8800
March 8, 2015	$2.8100	$2.8300	$2.9150	$2.8850		$2.8650	$2.9100		$2.8800
March 9, 2015	$2.8100	$2.8300	$2.9150	$2.8850		$2.8650	$2.9100		$2.8800
March 10, 2015	$2.5900	$2.6200	$2.6700	$2.6700	$2.6700	$2.6900	$2.7200		$2.7250
March 11, 2015	$2.6500	$2.6550	$2.6950	$2.7050	$2.7400	$2.7300	$2.7700	$2.9100	$2.7350
March 12, 2015	$2.6700	$2.7050	$2.7600	$2.7600	$2.7600	$2.7800	$2.8000		$2.7900
March 13, 2015	$2.7250	$2.7300	$2.8050	$2.8100	$2.8150	$2.8050	$2.8450		$2.8200
March 14, 2015	$2.5800	$2.5900	$2.6400	$2.6400	$2.7150	$2.6600	$2.7350		$2.6950
March 15, 2015	$2.5800	$2.5900	$2.6400	$2.6400	$2.7150	$2.6600	$2.7350		$2.6950
March 16, 2015	$2.5800	$2.5900	$2.6400	$2.6400	$2.7150	$2.6600	$2.7350		$2.6950
March 17, 2015	$2.5600	$2.5900	$2.6450	$2.6450	$2.6450	$2.6550	$2.7250		$2.6600
March 18, 2015	$2.7150	$2.7050	$2.8000	$2.7950	$2.8000	$2.8050	$2.8550		$2.7900
March 19, 2015	$2.6750	$2.6950	$2.7600	$2.7650	$2.7450	$2.7600	$2.8000		$2.7700
March 20, 2015	$2.7450	$2.7500	$2.8200	$2.8000	$2.8050	$2.8100	$2.8350	$3.0300	$2.8500
March 21, 2015	$2.7600	$2.7600	$2.8250	$2.8350	$2.8150	$2.8100	$2.8650		$2.8200
March 22, 2015	$2.7600	$2.7600	$2.8250	$2.8350	$2.8150	$2.8100	$2.8650		$2.8200
March 23, 2015	$2.7600	$2.7600	$2.8250	$2.8350	$2.8150	$2.8100	$2.8650		$2.8200
March 24, 2015	$2.6250	$2.6400	$2.6950	$2.6900	$2.6850	$2.6850	$2.7400		$2.6850
March 25, 2015	$2.6950	$2.7000	$2.7550	$2.7400	$2.7700	$2.7650	$2.8000	$2.9900	$2.7800
March 26, 2015	$2.6500	$2.6700	$2.7050	$2.7050	$2.7150	$2.7250	$2.7400		$2.7400
March 27, 2015	$2.6900	$2.6800	$2.7250	$2.7200	$2.7000	$2.7300	$2.7350	$2.9150	$2.7400
March 28, 2015	$2.5350	$2.5650	$2.6100	$2.6150		$2.6050	$2.6100	$2.8000	$2.6400
March 29, 2015	$2.5350	$2.5650	$2.6100	$2.6150		$2.6050	$2.6100	$2.8000	$2.6400
March 30, 2015	$2.5350	$2.5650	$2.6100	$2.6150		$2.6050	$2.6100	$2.8000	$2.6400
March 31, 2015	$2.5350	$2.5600	$2.6200	$2.6150	$2.5950	$2.6050	$2.6300	$2.7500	$2.6100
April 1, 2015	$2.5350	$2.5650	$2.6250	$2.6200	$2.5950	$2.6100	$2.6200	$2.7400	$2.6250
April 2, 2015	$2.5400	$2.5500	$2.5900	$2.5850	$2.5700	$2.6000	$2.6000		$2.5950
April 3, 2015	$2.5400	$2.5550	$2.6050	$2.6200	$2.5550	$2.5750	$2.6200		$2.5850
April 4, 2015	$2.5400	$2.5550	$2.6050	$2.6200	$2.5550	$2.5750	$2.6200		$2.5850
April 5, 2015	$2.5400	$2.5550	$2.6050	$2.6200	$2.5550	$2.5750	$2.6200		$2.5850
April 6, 2015	$2.5400	$2.5550	$2.6050	$2.6200	$2.5550	$2.5750	$2.6200		$2.5850
April 7, 2015	$2.3550	$2.5500	$2.5950	$2.5950	$2.5750	$2.6000	$2.6150		$2.6200
April 8, 2015	$2.3650	$2.5750	$2.6500	$2.6400	$2.5950	$2.6250	$2.6700		$2.6700
April 9, 2015	$2.6000	$2.5850	$2.6450	$2.6200	$2.6200	$2.6450	$2.7000	$2.9000	$2.6700
April 10, 2015	$2.5400	$2.5500	$2.6000	$2.5650	$2.5950	$2.6150	$2.6300	$2.8600	$2.6250

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Date	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Carthage Hub**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Columbia Gulf Mainline**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Transco Zone 4**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Sonat LA**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 1**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 2**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 3**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Florida City Gates**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Henry Hub**
April 11, 2015	$2.4500	$2.4600	$2.5000	$2.4900	$2.5100	$2.5250	$2.5500	$2.7500	$2.5450
April 12, 2015	$2.4500	$2.4600	$2.5000	$2.4900	$2.5100	$2.5250	$2.5500	$2.7500	$2.5450
April 13, 2015	$2.4500	$2.4600	$2.5000	$2.4900	$2.5100	$2.5250	$2.5500	$2.7500	$2.5450
April 14, 2015	$2.4550	$2.4550	$2.5050	$2.5050	$2.5200	$2.5150	$2.5600	$2.7850	$2.5600
April 15, 2015	$2.4650	$2.4700	$2.5150	$2.5050	$2.5250	$2.5200	$2.5950	$2.9000	$2.5600
April 16, 2015	$2.4950	$2.4850	$2.5450	$2.5400	$2.5550	$2.5400	$2.6150	$2.9500	$2.5800
April 17, 2015	$2.5050	$2.5100	$2.5450	$2.5400	$2.5550	$2.5650	$2.6200	$2.9000	$2.5800
April 18, 2015	$2.5700	$2.5750	$2.6200	$2.6100	$2.6050	$2.6300	$2.6750	$2.9500	$2.6350
April 19, 2015	$2.5700	$2.5750	$2.6200	$2.6100	$2.6050	$2.6300	$2.6750	$2.9500	$2.6350
April 20, 2015	$2.5700	$2.5750	$2.6200	$2.6100	$2.6050	$2.6300	$2.6750	$2.9500	$2.6350
April 21, 2015	$2.4650	$2.4600	$2.5000	$2.4900	$2.4900	$2.5150	$2.5300	$2.7400	$2.5350
April 22, 2015	$2.4900	$2.5100	$2.5500	$2.5300	$2.5300	$2.5500	$2.5650	$2.7900	$2.5650
April 23, 2015	$2.5400	$2.5350	$2.5650	$2.5550	$2.5550	$2.5800	$2.5950	$2.7800	$2.6050
April 24, 2015	$2.4950	$2.4900	$2.5250	$2.4950	$2.5150	$2.5350	$2.5650	$2.7550	$2.5550
April 25, 2015	$2.4800	$2.4900	$2.5200	$2.5100	$2.5150	$2.5350	$2.5450	$2.7450	$2.5600
April 26, 2015	$2.4800	$2.4900	$2.5200	$2.5100	$2.5150	$2.5350	$2.5450	$2.7450	$2.5600
April 27, 2015	$2.4800	$2.4900	$2.5200	$2.5100	$2.5150	$2.5350	$2.5450	$2.7450	$2.5600
April 28, 2015	$2.4250	$2.4200	$2.4650	$2.4550	$2.4450	$2.4600	$2.4800	$2.6500	$2.4850
April 29, 2015	$2.4650	$2.4600	$2.5200	$2.4950	$2.4950	$2.5050	$2.5200	$2.7000	$2.5350
April 30, 2015	$2.4950	$2.4850	$2.5400	$2.5150	$2.5100	$2.5300	$2.5450	$2.7500	$2.5550
May 1, 2015	$2.4750	$2.5000	$2.5400	$2.5100	$2.5100	$2.5350	$2.5450	$2.7500	$2.5650
May 2, 2015	$2.5600	$2.6250	$2.6750	$2.6600	$2.6450	$2.6700	$2.6900	$2.8800	$2.6650
May 3, 2015	$2.5600	$2.6250	$2.6750	$2.6600	$2.6450	$2.6700	$2.6900	$2.8800	$2.6650
May 4, 2015	$2.5600	$2.6250	$2.6750	$2.6600	$2.6450	$2.6700	$2.6900	$2.8800	$2.6650
May 5, 2015	$2.6500	$2.6750	$2.7350	$2.7250	$2.7100	$2.7250	$2.7550	$2.9450	$2.7200
May 6, 2015	$2.6750	$2.7050	$2.7550	$2.7550	$2.7300	$2.7450	$2.7700	$2.9600	$2.7600
May 7, 2015	$2.6550	$2.7000	$2.7500	$2.7450	$2.7200	$2.7400	$2.7600	$2.9200	$2.7450
May 8, 2015	$2.6900	$2.7200	$2.7650	$2.7650	$2.7400	$2.7550	$2.7800	$2.9600	$2.7750
May 9, 2015	$2.7500	$2.7300	$2.8150	$2.7900	$2.7650	$2.8150	$2.8400	$3.1050	$2.7700
May 10, 2015	$2.7500	$2.7300	$2.8150	$2.7900	$2.7650	$2.8150	$2.8400	$3.1050	$2.7700
May 11, 2015	$2.7500	$2.7300	$2.8150	$2.7900	$2.7650	$2.8150	$2.8400	$3.1050	$2.7700
May 12, 2015	$2.8100	$2.8100	$2.8950	$2.8600	$2.8450	$2.8600	$2.9200	$3.1850	$2.8550
May 13, 2015	$2.8200	$2.8200	$2.8800	$2.8650	$2.8550	$2.8800	$2.9750	$3.3000	$2.8500
May 14, 2015	$2.8250	$2.8100	$2.8600	$2.8650	$2.8350	$2.8700	$2.9700	$3.3000	$2.8600
May 15, 2015	$2.7800	$2.8200	$2.8700	$2.8700	$2.8450	$2.8650	$2.9550	$3.2900	$2.8700
May 16, 2015	$2.9000	$2.9100	$2.9800	$2.9650	$2.9300	$2.9600	$2.9900		$2.9600
May 17, 2015	$2.9000	$2.9100	$2.9800	$2.9650	$2.9300	$2.9600	$2.9900		$2.9600
May 18, 2015	$2.9000	$2.9100	$2.9800	$2.9650	$2.9300	$2.9600	$2.9900		$2.9600
May 19, 2015		$2.9650	$3.0450	$3.0150	$3.0200	$3.0600	$3.0900	$3.3250	$3.0050
May 20, 2015	$2.9850	$3.0400	$3.1150	$3.0800	$3.0850	$3.1100	$3.1800		$3.0650
May 21, 2015	$2.9400	$2.9500	$3.0150	$2.9850	$2.9900	$3.0450	$3.1100		$2.9900
May 22, 2015	$2.8400	$2.8650	$2.9350	$2.8950	$2.9100	$2.9550	$3.0800		$2.9300

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Date	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Carthage Hub**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Columbia Gulf Mainline**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Transco Zone 4**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Sonat LA**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 1**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 2**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 3**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Florida City Gates**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Henry Hub**
May 23, 2015	$2.7750	$2.8250	$2.9150	$2.8650	$2.8700	$2.9150	$3.0250		$2.8850
May 24, 2015	$2.7750	$2.8250	$2.9150	$2.8650	$2.8700	$2.9150	$3.0250		$2.8850
May 25, 2015	$2.7750	$2.8250	$2.9150	$2.8650	$2.8700	$2.9150	$3.0250		$2.8850
May 26, 2015	$2.7750	$2.8250	$2.9150	$2.8650	$2.8700	$2.9150	$3.0250		$2.8850
May 27, 2015	$2.7250	$2.7350	$2.8500	$2.7700	$2.8200	$2.8150	$2.9450		$2.8200
May 28, 2015	$2.7700	$2.7500	$2.8450	$2.7700	$2.8000	$2.8400	$2.9100		$2.8250
May 29, 2015	$2.6950	$2.6850	$2.7700	$2.7100	$2.7200	$2.7650	$2.8550		$2.7750
May 30, 2015	$2.6950	$2.6850	$2.7700	$2.7100	$2.7200	$2.7650	$2.8550		$2.7750
May 31, 2015	$2.6950	$2.6850	$2.7700	$2.7100	$2.7200	$2.7650	$2.8550		$2.7750
June 1, 2015	$2.5700	$2.5600	$2.6350	$2.6000	$2.6100	$2.6200	$2.7500	$2.9400	$2.6500
June 2, 2015	$2.5800	$2.5450	$2.6100	$2.5750	$2.5550	$2.5800	$2.6500	$2.8500	$2.6000
June 3, 2015	$2.5400	$2.5450	$2.6050	$2.5850	$2.5800		$2.6450	$2.8300	$2.6250
June 4, 2015	$2.5700	$2.5600	$2.6250	$2.5950	$2.5950	$2.5950	$2.6650	$2.8600	$2.6350
June 5, 2015	$2.4900	$2.5150	$2.5750	$2.5750	$2.5700	$2.5750	$2.6100		$2.5950
June 6, 2015	$2.5100	$2.4900	$2.5500	$2.5350	$2.5150	$2.5300	$2.5800		$2.5600
June 7, 2015	$2.5100	$2.4900	$2.5500	$2.5350	$2.5150	$2.5300	$2.5800		$2.5600
June 8, 2015	$2.5100	$2.4900	$2.5500	$2.5350	$2.5150	$2.5300	$2.5800		$2.5600
June 9, 2015	$2.6300	$2.6200	$2.6900	$2.6700	$2.6250	$2.6400	$2.6700	$2.8500	$2.6850
June 10, 2015	$2.7550	$2.7550	$2.8400	$2.7900	$2.8000	$2.8250	$2.8600		$2.8150
June 11, 2015	$2.8150	$2.8400	$2.9050	$2.8900	$2.8850	$2.9150	$2.9150	$3.1550	$2.9200
June 12, 2015	$2.7850	$2.7950	$2.8600	$2.8500	$2.8350	$2.8500	$2.8850		$2.8750
June 13, 2015	$2.7150	$2.7150	$2.7850	$2.7750	$2.7400	$2.7450	$2.8000	$3.0000	$2.7650
June 14, 2015	$2.7150	$2.7150	$2.7850	$2.7750	$2.7400	$2.7450	$2.8000	$3.0000	$2.7650
June 15, 2015	$2.7150	$2.7150	$2.7850	$2.7750	$2.7400	$2.7450	$2.8000	$3.0000	$2.7650
June 16, 2015	$2.8300	$2.8200	$2.9000	$2.8750	$2.8550	$2.8650	$2.9150	$3.2600	$2.8600
June 17, 2015	$2.8450	$2.8700	$2.9100	$2.9200	$2.8950	$2.9300	$2.9500	$3.4000	$2.9350
June 18, 2015	$2.8700	$2.8750	$2.9500	$2.9400	$2.8950	$2.9250	$2.9700	$3.4100	$2.9350
June 19, 2015	$2.8200	$2.7950	$2.8900	$2.8600	$2.8300	$2.8500	$2.9450	$4.4650	$2.8550
June 20, 2015	$2.7450	$2.7400	$2.8000	$2.7950	$2.7600	$2.7950	$2.8750	$4.4450	$2.8050
June 21, 2015	$2.7450	$2.7400	$2.8000	$2.7950	$2.7600	$2.7950	$2.8750	$4.4450	$2.8050
June 22, 2015	$2.7450	$2.7400	$2.8000	$2.7950	$2.7600	$2.7950	$2.8750	$4.4450	$2.8050
June 23, 2015	$2.7200	$2.7100	$2.8150	$2.7850	$2.7450	$2.7750	$2.8750	$4.7650	$2.7750
June 24, 2015	$2.7800	$2.7800	$2.8500	$2.8300	$2.7950	$2.8400	$2.9100	$4.7150	$2.8300
June 25, 2015	$2.7100	$2.7150	$2.7850	$2.7700	$2.7300	$2.7700	$2.8200	$3.4500	$2.7700
June 26, 2015	$2.7650	$2.7450	$2.8000	$2.7950	$2.7600	$2.7950	$2.8500	$3.3100	$2.7900
June 27, 2015	$2.7300	$2.7050	$2.7650	$2.7400	$2.7200	$2.7500	$2.8400	$3.1700	$2.7700
June 28, 2015	$2.7300	$2.7050	$2.7650	$2.7400	$2.7200	$2.7500	$2.8400	$3.1700	$2.7700
June 29, 2015	$2.7300	$2.7050	$2.7650	$2.7400	$2.7200	$2.7500	$2.8400	$3.1700	$2.7700
June 30, 2015	$2.7550	$2.7400	$2.8050	$2.8000	$2.7800	$2.7950	$2.8400	$3.1750	$2.8050
July 1, 2015	$2.6900	$2.7200	$2.7650	$2.7400	$2.7300	$2.7500	$2.7700	$3.0850	$2.7750
July 2, 2015	$2.7400	$2.7350	$2.7800	$2.7650	$2.7800	$2.7900	$2.8200	$3.1900	$2.8100
July 3, 2015	$2.7300	$2.7350	$2.7850	$2.7550	$2.7600	$2.7650	$2.8450		$2.7900

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Date	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Carthage Hub**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Columbia Gulf Mainline**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Transco Zone 4**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Sonat LA**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 1**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 2**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 3**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Florida City Gates**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Henry Hub**
July 4, 2015	$2.7300	$2.7350	$2.7850	$2.7550	$2.7600	$2.7650	$2.8450		$2.7900
July 5, 2015	$2.7300	$2.7350	$2.7850	$2.7550	$2.7600	$2.7650	$2.8450		$2.7900
July 6, 2015	$2.7300	$2.7350	$2.7850	$2.7550	$2.7600	$2.7650	$2.8450		$2.7900
July 7, 2015	$2.6800	$2.6850	$2.7350	$2.7100	$2.7000	$2.7150	$2.7750		$2.7400
July 8, 2015	$2.6850	$2.6750	$2.7250	$2.6950	$2.6950	$2.7050	$2.7550		$2.7300
July 9, 2015	$2.6650	$2.6850	$2.7400	$2.7000	$2.6900	$2.7100	$2.7600		$2.7100
July 10, 2015	$2.6100	$2.6400	$2.7050	$2.6700	$2.6450	$2.6600	$2.7300		$2.6850
July 11, 2015	$2.7200	$2.7200	$2.7750	$2.7400	$2.7100	$2.7350	$2.8350		$2.7450
July 12, 2015	$2.7200	$2.7200	$2.7750	$2.7400	$2.7100	$2.7350	$2.8350		$2.7450
July 13, 2015	$2.7200	$2.7200	$2.7750	$2.7400	$2.7100	$2.7350	$2.8350		$2.7450
July 14, 2015	$2.8350	$2.8300	$2.9000	$2.8700	$2.8600	$2.8800	$2.9200		$2.8800
July 15, 2015	$2.9000	$2.9000	$2.9600	$2.9350	$2.9150	$2.9550	$2.9800	$3.2850	$2.9450
July 16, 2015	$2.8900	$2.8750	$2.9250	$2.9100	$2.9050	$2.9350	$2.9100		$2.9200
July 17, 2015	$2.8100	$2.8500	$2.8800	$2.8700	$2.8650	$2.8750	$2.8800		$2.9000
July 18, 2015	$2.8000	$2.8150	$2.8600	$2.8400	$2.8300	$2.8250	$2.8650		$2.8450
July 19, 2015	$2.8000	$2.8150	$2.8600	$2.8400	$2.8300	$2.8250	$2.8650		$2.8450
July 20, 2015	$2.8000	$2.8150	$2.8600	$2.8400	$2.8300	$2.8250	$2.8650		$2.8450
July 21, 2015	$2.7750	$2.8000	$2.8500	$2.8300	$2.8150	$2.8300	$2.8550		$2.8350
July 22, 2015	$2.8400	$2.8500	$2.8950	$2.8800	$2.8750	$2.8800	$2.9350	$3.1400	$2.8850
July 23, 2015	$2.8500	$2.8650	$2.9050	$2.9000	$2.8850	$2.9100	$2.9250	$3.1250	$2.8950
July 24, 2015	$2.8450	$2.8650	$2.9000	$2.8950	$2.8750	$2.8900	$2.9100		$2.9150
July 25, 2015	$2.7550	$2.7700	$2.8100	$2.7950	$2.7900	$2.7950	$2.8150		$2.8150
July 26, 2015	$2.7550	$2.7700	$2.8100	$2.7950	$2.7900	$2.7950	$2.8150		$2.8150
July 27, 2015	$2.7550	$2.7700	$2.8100	$2.7950	$2.7900	$2.7950	$2.8150		$2.8150
July 28, 2015	$2.7550	$2.7900	$2.8500	$2.8300	$2.8000	$2.8200	$2.8450		$2.8350
July 29, 2015	$2.7900	$2.8350	$2.8800	$2.8600	$2.8500	$2.8700	$2.8750		$2.8750
July 30, 2015	$2.8100	$2.8550	$2.9000	$2.8950	$2.8700	$2.8750	$2.8900		$2.9000
July 31, 2015	$2.7900	$2.7900	$2.8450	$2.8350	$2.8200	$2.8400	$2.8400		$2.8500
August 1, 2015	$2.7350	$2.7100	$2.7700	$2.7550	$2.7300	$2.7400	$2.7650		$2.7650
August 2, 2015	$2.7350	$2.7100	$2.7700	$2.7550	$2.7300	$2.7400	$2.7650		$2.7650
August 3, 2015	$2.7350	$2.7100	$2.7700	$2.7550	$2.7300	$2.7400	$2.7650		$2.7650
August 4, 2015	$2.6900	$2.7100	$2.7600	$2.7400	$2.7200	$2.7400	$2.7550		$2.7550
August 5, 2015	$2.7650	$2.7850	$2.8300	$2.8100	$2.8000	$2.8150	$2.8350		$2.8200
August 6, 2015	$2.8150	$2.8250	$2.8700	$2.8650	$2.8300	$2.8650	$2.8850	$3.3300	$2.8550
August 7, 2015	$2.7350	$2.7250	$2.7700	$2.7550	$2.7500	$2.7550	$2.7950	$3.1600	$2.7650
August 8, 2015	$2.7650	$2.7850	$2.8300	$2.8100	$2.8150	$2.8100	$2.8450	$3.1200	$2.8100
August 9, 2015	$2.7650	$2.7850	$2.8300	$2.8100	$2.8150	$2.8100	$2.8450	$3.1200	$2.8100
August 10, 2015	$2.7650	$2.7850	$2.8300	$2.8100	$2.8150	$2.8100	$2.8450	$3.1200	$2.8100
August 11, 2015	$2.7900	$2.8200	$2.8650	$2.8600	$2.8400	$2.8600	$2.8900	$3.1700	$2.8500
August 12, 2015	$2.7950	$2.8050	$2.8600	$2.8400	$2.8250	$2.8450	$2.8850		$2.8450
August 13, 2015	$2.8650	$2.8500	$2.9150	$2.8850	$2.8800	$2.8950	$2.9200	$3.2000	$2.9150
August 14, 2015	$2.8000	$2.8650	$2.9100	$2.8900	$2.8900	$2.9000	$2.9050		$2.9150

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Date	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Carthage Hub**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Columbia Gulf Mainline**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Transco Zone 4**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Sonat LA**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 1**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 2**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 3**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Florida City Gates**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Henry Hub**
August 15, 2015	$2.7700	$2.7700	$2.8350	$2.8100	$2.8100	$2.8150	$2.8400		$2.8250
August 16, 2015	$2.7700	$2.7700	$2.8350	$2.8100	$2.8100	$2.8150	$2.8400		$2.8250
August 17, 2015	$2.7700	$2.7700	$2.8350	$2.8100	$2.8100	$2.8150	$2.8400		$2.8250
August 18, 2015	$2.7250	$2.7250	$2.7850	$2.7550	$2.7300	$2.7550	$2.7800		$2.7650
August 19, 2015	$2.6800	$2.6750	$2.7300	$2.7050	$2.6850	$2.7100	$2.7400	$2.9700	$2.7100
August 20, 2015	$2.6700	$2.6850	$2.7500	$2.7200	$2.7050	$2.7300	$2.7750		$2.7300
August 21, 2015	$2.6500	$2.6500	$2.7200	$2.6850	$2.6750	$2.7000	$2.7500	$3.0300	$2.7100
August 22, 2015	$2.6500	$2.6300	$2.7150	$2.6850	$2.6600	$2.6850	$2.7450	$3.0850	$2.7000
August 23, 2015	$2.6500	$2.6300	$2.7150	$2.6850	$2.6600	$2.6850	$2.7450	$3.0850	$2.7000
August 24, 2015	$2.6500	$2.6300	$2.7150	$2.6850	$2.6600	$2.6850	$2.7450	$3.0850	$2.7000
August 25, 2015	$2.5800	$2.5950	$2.6750	$2.6400	$2.6300	$2.6400	$2.7300	$3.2000	$2.6400
August 26, 2015	$2.6600	$2.6400	$2.7150	$2.6850	$2.6750	$2.6950	$2.7400	$3.4100	$2.6950
August 27, 2015	$2.6550	$2.6450	$2.7150	$2.6900	$2.6900	$2.7000	$2.7450	$3.5000	$2.7250
August 28, 2015	$2.6100	$2.6150	$2.6600	$2.6500	$2.6500	$2.6500	$2.6600	$2.9400	$2.6850
August 29, 2015	$2.6000	$2.6050	$2.6600	$2.6500	$2.6350	$2.6350	$2.6600		$2.6550
August 30, 2015	$2.6000	$2.6050	$2.6600	$2.6500	$2.6350	$2.6350	$2.6600		$2.6550
August 31, 2015	$2.6000	$2.6050	$2.6600	$2.6500	$2.6350	$2.6350	$2.6600		$2.6550
September 1, 2015	$2.6050	$2.6150	$2.6850	$2.6550	$2.6450	$2.6700	$2.7050	$2.9400	$2.6850
September 2, 2015	$2.6900	$2.6750	$2.7550	$2.7200	$2.7050	$2.7300	$2.7750	$3.0300	$2.7450
September 3, 2015	$2.6750	$2.6450	$2.7250	$2.7050	$2.6750	$2.7050	$2.7500	$3.2900	$2.7200
September 4, 2015	$2.6100	$2.6100	$2.6800	$2.6700	$2.6400	$2.6650	$2.7050	$3.1600	$2.6750
September 5, 2015	$2.6200	$2.6250	$2.6700	$2.6550	$2.6400	$2.6650	$2.6700		$2.6700
September 6, 2015	$2.6200	$2.6250	$2.6700	$2.6550	$2.6400	$2.6650	$2.6700		$2.6700
September 7, 2015	$2.6200	$2.6250	$2.6700	$2.6550	$2.6400	$2.6650	$2.6700		$2.6700
September 8, 2015	$2.6200	$2.6250	$2.6700	$2.6550	$2.6400	$2.6650	$2.6700		$2.6700
September 9, 2015	$2.6700	$2.6600	$2.7350	$2.7200	$2.7000	$2.7100	$2.7500	$3.0500	$2.7350
September 10, 2015	$2.6450	$2.6250	$2.7050	$2.6900	$2.6750	$2.7000	$2.7400	$3.2000	$2.7300
September 11, 2015	$2.6000	$2.6050	$2.6650	$2.6550	$2.6400	$2.6500	$2.6950	$3.0100	$2.7050
September 12, 2015	$2.6000	$2.6000	$2.6500	$2.6400	$2.6000	$2.6400	$2.6700		$2.6650
September 13, 2015	$2.6000	$2.6000	$2.6500	$2.6400	$2.6000	$2.6400	$2.6700		$2.6650
September 14, 2015	$2.6000	$2.6000	$2.6500	$2.6400	$2.6000	$2.6400	$2.6700		$2.6650
September 15, 2015	$2.6050	$2.6150	$2.6700	$2.6600	$2.6500	$2.6800	$2.7150		$2.7000
September 16, 2015	$2.6500	$2.6500	$2.6950	$2.6900	$2.6750	$2.7000	$2.7250		$2.7300
September 17, 2015	$2.6000	$2.5900	$2.6450	$2.6400	$2.6100	$2.6450	$2.6400		$2.6850
September 18, 2015	$2.5750	$2.5700	$2.6150	$2.6050	$2.6050	$2.6100	$2.6100		$2.6750
September 19, 2015	$2.5350	$2.5200	$2.5800	$2.5650	$2.5650		$2.5750		$2.6250
September 20, 2015	$2.5350	$2.5200	$2.5800	$2.5650	$2.5650		$2.5750		$2.6250
September 21, 2015	$2.5350	$2.5200	$2.5800	$2.5650	$2.5650		$2.5750		$2.6250
September 22, 2015	$2.5100	$2.4950	$2.5550	$2.5450	$2.5450	$2.5500	$2.5650		$2.5900
September 23, 2015	$2.5350	$2.5000	$2.5550	$2.5450	$2.5400	$2.5450	$2.5500		$2.5850
September 24, 2015	$2.5300	$2.5050	$2.5550	$2.5500	$2.5400	$2.5500	$2.5500	$2.8600	$2.5900
September 25, 2015	$2.4750	$2.4800	$2.5200	$2.5150	$2.5200	$2.5300	$2.5300	$2.8600	$2.5650

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Date	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Carthage Hub**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Columbia Gulf Mainline**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Transco Zone 4**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Sonat LA**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 1**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 2**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 3**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Florida City Gates**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Henry Hub**
September 26, 2015	$2.4650	$2.4500	$2.4850	$2.4800	$2.5000	$2.5050	$2.5000	$2.8000	$2.5450
September 27, 2015	$2.4650	$2.4500	$2.4850	$2.4800	$2.5000	$2.5050	$2.5000	$2.8000	$2.5450
September 28, 2015	$2.4650	$2.4500	$2.4850	$2.4800	$2.5000	$2.5050	$2.5000	$2.8000	$2.5450
September 29, 2015	$2.5100	$2.5400	$2.5750	$2.5750	$2.5800	$2.5900	$2.5850		$2.6350
September 30, 2015	$2.4600	$2.4550	$2.5100	$2.4900	$2.4850	$2.4950	$2.5200		$2.5300
October 1, 2015	$2.3850	$2.3950	$2.4550	$2.4350	$2.4400	$2.4450	$2.4800	$2.7300	$2.4750
October 2, 2015	$2.3150	$2.3100	$2.3600	$2.3450	$2.3400	$2.3500	$2.3650	$2.6600	$2.3750
October 3, 2015	$2.2100	$2.2000	$2.2900	$2.2550	$2.2300	$2.2450	$2.2600	$2.5800	$2.2650
October 4, 2015	$2.2100	$2.2000	$2.2900	$2.2550	$2.2300	$2.2450	$2.2600	$2.5800	$2.2650
October 5, 2015	$2.2100	$2.2000	$2.2900	$2.2550	$2.2300	$2.2450	$2.2600	$2.5800	$2.2650
October 6, 2015	$2.1850	$2.2550	$2.3000	$2.2950	$2.2700	$2.2950	$2.3000		$2.3250
October 7, 2015	$2.2750	$2.2800	$2.3350	$2.3100	$2.3250	$2.3150	$2.3100		$2.3500
October 8, 2015	$2.3450	$2.3650	$2.4450	$2.4100	$2.4150	$2.4150	$2.4500	$2.6850	$2.4600
October 9, 2015	$2.3500	$2.3550	$2.4150	$2.3850	$2.4100	$2.4200	$2.4250		$2.4350
October 10, 2015	$2.3050	$2.2950	$2.3650	$2.3500	$2.3300	$2.3450	$2.3650		$2.3750
October 11, 2015	$2.3050	$2.2950	$2.3650	$2.3500	$2.3300	$2.3450	$2.3650		$2.3750
October 12, 2015	$2.3050	$2.2950	$2.3650	$2.3500	$2.3300	$2.3450	$2.3650		$2.3750
October 13, 2015	$2.3700	$2.3700	$2.4400	$2.4200	$2.4050	$2.4200	$2.4350		$2.4350
October 14, 2015	$2.3450	$2.3550	$2.4150	$2.4150	$2.3950	$2.3950	$2.4200		$2.4400
October 15, 2015	$2.3700	$2.3700	$2.4350	$2.4250	$2.4150	$2.4250	$2.4350		$2.4350
October 16, 2015	$2.4250	$2.4400	$2.4800	$2.4800	$2.4800	$2.4900	$2.4850		$2.4950
October 17, 2015	$2.3250	$2.3350	$2.3800	$2.3750	$2.3600	$2.3700	$2.3750		$2.3800
October 18, 2015	$2.3250	$2.3350	$2.3800	$2.3750	$2.3600	$2.3700	$2.3750		$2.3800
October 19, 2015	$2.3250	$2.3350	$2.3800	$2.3750	$2.3600	$2.3700	$2.3750		$2.3800
October 20, 2015	$2.3400	$2.3400	$2.3800	$2.3700	$2.3750	$2.3800	$2.3850		$2.4300
October 21, 2015	$2.3300	$2.3350	$2.3800	$2.3800	$2.3600	$2.3800	$2.3700		$2.4450
October 22, 2015	$2.2400	$2.2700	$2.3150	$2.3100	$2.2800	$2.3050	$2.3050		$2.3600
October 23, 2015	$2.2200	$2.2700	$2.3000	$2.3050	$2.2800	$2.2950	$2.2950		$2.3400
October 24, 2015	$2.1500	$2.1700	$2.2150	$2.2050	$2.2000	$2.2050	$2.2150		$2.2650
October 25, 2015	$2.1500	$2.1700	$2.2150	$2.2050	$2.2000	$2.2050	$2.2150		$2.2650
October 26, 2015	$2.1500	$2.1700	$2.2150	$2.2050	$2.2000	$2.2050	$2.2150		$2.2650
October 27, 2015	$2.0550	$2.0750	$2.1250	$2.1200	$2.1200	$2.1150	$2.1250	$2.3900	$2.1400
October 28, 2015	$1.9850	$2.0250	$2.0700	$2.0700	$2.0450	$2.0550	$2.0700	$2.3200	$2.0750
October 29, 2015	$2.0350	$2.0450	$2.0950	$2.0900	$2.0650	$2.0850	$2.0850	$2.3450	$2.1000
October 30, 2015	$2.0450	$2.0750	$2.1100	$2.1050	$2.0850	$2.0900	$2.1000	$2.3650	$2.1100
October 31, 2015	$2.0450	$2.0750	$2.1100	$2.1050	$2.0850	$2.0900	$2.1000	$2.3650	$2.1100
November 1, 2015	$1.8650	$1.9050	$1.9600	$1.9350	$1.9300	$1.9450	$1.9750	$2.2200	$1.9650
November 2, 2015	$1.8650	$1.9050	$1.9600	$1.9350	$1.9300	$1.9450	$1.9750	$2.2200	$1.9650
November 3, 2015	$1.8250	$1.8600	$1.9500	$1.9100	$1.8850	$1.9050	$2.0300	$2.3850	$1.9200
November 4, 2015	$1.8500	$1.8350	$1.9350	$1.9000	$1.9000	$1.9050	$2.0200	$2.8550	$1.9000
November 5, 2015	$1.9650	$1.9700	$2.0300	$2.0200	$2.0250	$1.9900	$2.0900	$2.7100	$2.0200
November 6, 2015	$2.0700	$2.0500	$2.1050	$2.1000	$2.0800	$2.0800	$2.1400	$2.6950	$2.0900

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Date	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Carthage Hub**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Columbia Gulf Mainline**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Transco Zone 4**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Sonat LA**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 1**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 2**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 3**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Florida City Gates**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Henry Hub**
November 7, 2015	$2.0600	$2.0800	$2.1650	$2.1400	$2.1300	$2.1700	$2.2150	$2.5350	$2.1700
November 8, 2015	$2.0600	$2.0800	$2.1650	$2.1400	$2.1300	$2.1700	$2.2150	$2.5350	$2.1700
November 9, 2015	$2.0600	$2.0800	$2.1650	$2.1400	$2.1300	$2.1700	$2.2150	$2.5350	$2.1700
November 10, 2015	$2.0250	$2.0350	$2.1000	$2.0850	$2.0800	$2.0750	$2.1350	$2.5100	$2.1200
November 11, 2015	$2.0350	$2.0600	$2.1150	$2.1000	$2.0650	$2.1000	$2.1550	$2.4500	$2.1150
November 12, 2015	$1.9800	$2.0400	$2.0950	$2.0800	$2.0950	$2.1000	$2.1150	$2.4700	$2.1150
November 13, 2015	$1.8950	$1.9400	$1.9700	$1.9650		$1.9500	$1.9800	$2.3000	$2.0100
November 14, 2015	$1.9150	$1.9550	$2.0100	$1.9900	$1.9700	$1.9750	$2.0050	$2.3200	$2.0100
November 15, 2015	$1.9150	$1.9550	$2.0100	$1.9900	$1.9700	$1.9750	$2.0050	$2.3200	$2.0100
November 16, 2015	$1.9150	$1.9550	$2.0100	$1.9900	$1.9700	$1.9750	$2.0050	$2.3200	$2.0100
November 17, 2015	$2.0100	$2.0300	$2.0550	$2.0550	$2.0450	$2.0700	$2.0550		$2.1350
November 18, 2015	$1.9100	$1.9450	$1.9700	$1.9750	$1.9650	$1.9700	$1.9750	$2.3550	$2.0500
November 19, 2015	$2.0350	$2.0450	$2.0600	$2.0650	$2.0650	$2.0800	$2.1000	$2.3900	$2.1000
November 20, 2015	$2.0800	$2.1000	$2.1600	$2.1350	$2.1400	$2.1450	$2.1700	$2.4000	$2.1550
November 21, 2015	$2.1350	$2.1500	$2.2000	$2.1850	$2.1650	$2.1800	$2.1900	$2.4300	$2.1600
November 22, 2015	$2.1350	$2.1500	$2.2000	$2.1850	$2.1650	$2.1800	$2.1900	$2.4300	$2.1600
November 23, 2015	$2.1350	$2.1500	$2.2000	$2.1850	$2.1650	$2.1800	$2.1900	$2.4300	$2.1600
November 24, 2015	$2.0950	$2.1050	$2.1600	$2.1500	$2.1150	$2.1400	$2.1550		$2.1350
November 25, 2015	$2.0600	$2.0700	$2.1400	$2.1050	$2.1050	$2.1100	$2.1500		$2.1100
November 26, 2015	$1.9500	$1.9500	$1.9850	$1.9800	$1.9600	$1.9750	$2.0000	$2.2000	$2.0600
November 27, 2015	$1.9500	$1.9500	$1.9850	$1.9800	$1.9600	$1.9750	$2.0000	$2.2000	$2.0600
November 28, 2015	$1.9500	$1.9500	$1.9850	$1.9800	$1.9600	$1.9750	$2.0000	$2.2000	$2.0600
November 29, 2015	$1.9500	$1.9500	$1.9850	$1.9800	$1.9600	$1.9750	$2.0000	$2.2000	$2.0600
November 30, 2015	$1.9500	$1.9500	$1.9850	$1.9800	$1.9600	$1.9750	$2.0000	$2.2000	$2.0600
December 1, 2015	$2.0600	$2.0500	$2.1150	$2.0600	$2.0500	$2.0750	$2.1350	$2.3500	$2.0950
December 2, 2015	$2.1300	$2.1050	$2.1900	$2.1500	$2.1450	$2.1300	$2.2000	$2.4500	$2.1400
December 3, 2015	$2.1650	$2.1500	$2.2000	$2.1850	$2.1900	$2.1950	$2.2100		$2.1750
December 4, 2015	$2.0600	$2.0750	$2.1150	$2.0950	$2.0800	$2.0950	$2.1000		$2.1100
December 5, 2015	$2.0400	$2.0400	$2.1250	$2.0650	$2.1000	$2.0750	$2.1200		$2.0850
December 6, 2015	$2.0400	$2.0400	$2.1250	$2.0650	$2.1000	$2.0750	$2.1200		$2.0850
December 7, 2015	$2.0400	$2.0400	$2.1250	$2.0650	$2.1000	$2.0750	$2.1200		$2.0850
December 8, 2015	$1.9750	$1.9750	$2.0600	$2.0250		$2.0200	$2.0600	$2.2600	$2.0300
December 9, 2015	$1.9300	$1.9300	$2.0050	$1.9550		$2.0000	$2.0000		$1.9750
December 10, 2015	$1.9300	$1.9300	$1.9850	$1.9550		$1.9600	$1.9950		$2.0000
December 11, 2015	$1.8500	$1.8250	$1.8850	$1.8500		$1.8500	$1.8850	$2.0850	$1.9050
December 12, 2015	$1.6500	$1.6850	$1.6850	$1.6700	$1.7000	$1.6950	$1.7450	$1.9400	$1.7600
December 13, 2015	$1.6500	$1.6850	$1.6850	$1.6700	$1.7000	$1.6950	$1.7450	$1.9400	$1.7600
December 14, 2015	$1.6500	$1.6850	$1.6850	$1.6700	$1.7000	$1.6950	$1.7450	$1.9400	$1.7600
December 15, 2015	$1.6350	$1.6250	$1.6950	$1.6550	$1.6600	$1.7150	$1.7150	$2.0300	$1.6900
December 16, 2015	$1.6150	$1.5900	$1.6600	$1.6150		$1.6000	$1.6800	$1.9500	$1.6500
December 17, 2015	$1.6650	$1.6550	$1.7100	$1.6850		$1.7000	$1.7350	$1.9800	$1.6750
December 18, 2015	$1.7050	$1.6950	$1.7450	$1.7300		$1.7200	$1.7400		$1.7500

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Date	Platts Gas GD - Gas Daily Settle (USD /MMBtu) Carthage Hub	Platts Gas GD - Gas Daily Settle (USD /MMBtu) Columbia Gulf Mainline	Platts Gas GD - Gas Daily Settle (USD /MMBtu) Transco Zone 4	Platts Gas GD - Gas Daily Settle (USD /MMBtu) Sonat LA	Platts Gas GD - Gas Daily Settle (USD /MMBtu) FGT Zone 1	Platts Gas GD - Gas Daily Settle (USD /MMBtu) FGT Zone 2	Platts Gas GD - Gas Daily Settle (USD /MMBtu) FGT Zone 3	Platts Gas GD - Gas Daily Settle (USD /MMBtu) Florida City Gates	Platts Gas GD - Gas Daily Settle (USD /MMBtu) Henry Hub
December 19, 2015	$1.6450	$1.6550	$1.7050	$1.6800	$1.6700	$1.6900	$1.7000		$1.7000
December 20, 2015	$1.6450	$1.6550	$1.7050	$1.6800	$1.6700	$1.6900	$1.7000		$1.7000
December 21, 2015	$1.6450	$1.6550	$1.7050	$1.6800	$1.6700	$1.6900	$1.7000		$1.7000
December 22, 2015	$1.6800	$1.6650	$1.7400	$1.7400		$1.7000	$1.7300	$1.9200	$1.7100
December 23, 2015	$1.6700	$1.6500	$1.7150	$1.6750	$1.7050	$1.7100	$1.7500		$1.7500
December 24, 2015	$1.5450	$1.4900	$1.5400	$1.5150	$1.5050		$1.6000		$1.6250
December 25, 2015	$1.4150	$1.4250	$1.4750	$1.4300	$1.5150		$1.5000		$1.5350
December 26, 2015	$1.4150	$1.4250	$1.4750	$1.4300	$1.5150		$1.5000		$1.5350
December 27, 2015	$1.4150	$1.4250	$1.4750	$1.4300	$1.5150		$1.5000		$1.5350
December 28, 2015	$1.4150	$1.4250	$1.4750	$1.4300	$1.5150		$1.5000		$1.5350
December 29, 2015	$2.0800	$2.0550	$2.1400	$2.0850	$2.1000	$2.1000	$2.1750	$2.3300	$2.0800
December 30, 2015	$2.3550	$2.3100	$2.3650	$2.3500	$2.3600	$2.3650	$2.4100		$2.3600
December 31, 2015	$2.2050	$2.1800	$2.2400	$2.2300	$2.2500	$2.2650	$2.3050		$2.2700
January 1, 2016	$2.3050	$2.2950	$2.3550	$2.3200	$2.3250	$2.2900	$2.3350		$2.3100
January 2, 2016	$2.3050	$2.2950	$2.3550	$2.3200	$2.3250	$2.2900	$2.3350		$2.3100
January 3, 2016	$2.3050	$2.2950	$2.3550	$2.3200	$2.3250	$2.2900	$2.3350		$2.3100
January 4, 2016	$2.3050	$2.2950	$2.3550	$2.3200	$2.3250	$2.2900	$2.3350		$2.3100
January 5, 2016	$2.3400	$2.3650	$2.4000	$2.3900	$2.3700	$2.3850	$2.3950		$2.3850
January 6, 2016	$2.2700	$2.2700	$2.3300	$2.3050	$2.2900	$2.3100	$2.3300		$2.3250
January 7, 2016	$2.2950	$2.2950	$2.3550	$2.3300	$2.3300	$2.3200	$2.3450		$2.3450
January 8, 2016	$2.2800	$2.2850	$2.3450	$2.3250	$2.3050	$2.3350	$2.3450		$2.3450
January 9, 2016	$2.4000	$2.4050	$2.4550	$2.4450	$2.4100	$2.4450	$2.4500		$2.4700
January 10, 2016	$2.4000	$2.4050	$2.4550	$2.4450	$2.4100	$2.4450	$2.4500		$2.4700
January 11, 2016	$2.4000	$2.4050	$2.4550	$2.4450	$2.4100	$2.4450	$2.4500		$2.4700
January 12, 2016	$2.4200	$2.4550	$2.4950	$2.4850	$2.4500	$2.4900	$2.4900		$2.5250
January 13, 2016	$2.2900	$2.3000	$2.3750	$2.3300	$2.3300	$2.3650	$2.3900	$4.1200	$2.3850
January 14, 2016	$2.2300	$2.2300	$2.3050	$2.2550	$2.2550	$2.2850	$2.3250		$2.3050
January 15, 2016	$2.1500	$2.1550	$2.1950	$2.1750	$2.1800	$2.1900	$2.2300		$2.1950
January 16, 2016	$2.1400	$2.1600	$2.1950	$2.1900	$2.1600	$2.1900	$2.1850	$2.5050	$2.1900
January 17, 2016	$2.1400	$2.1600	$2.1950	$2.1900	$2.1600	$2.1900	$2.1850	$2.5050	$2.1900
January 18, 2016	$2.1400	$2.1600	$2.1950	$2.1900	$2.1600	$2.1900	$2.1850	$2.5050	$2.1900
January 19, 2016	$2.1400	$2.1600	$2.1950	$2.1900	$2.1600	$2.1900	$2.1850	$2.5050	$2.1900
January 20, 2016	$2.1300	$2.1450	$2.1900	$2.1800	$2.1400	$2.1950	$2.2100	$2.5400	$2.2150
January 21, 2016	$2.1000	$2.1050	$2.1550	$2.1350	$2.1050	$2.1250	$2.1650	$2.4500	$2.1450
January 22, 2016	$2.1550	$2.1600	$2.2150	$2.1900	$2.1500	$2.2000	$2.2100	$2.4500	$2.2000
January 23, 2016	$2.1350	$2.1550	$2.2000	$2.1750	$2.1600	$2.1950	$2.2100	$2.7950	$2.2250
January 24, 2016	$2.1350	$2.1550	$2.2000	$2.1750	$2.1600	$2.1950	$2.2100	$2.7950	$2.2250
January 25, 2016	$2.1350	$2.1550	$2.2000	$2.1750	$2.1600	$2.1950	$2.2100	$2.7950	$2.2250
January 26, 2016	$2.0850	$2.0850	$2.1450	$2.1100	$2.1100	$2.1200	$2.1700	$2.4500	$2.1500
January 27, 2016	$2.1800	$2.1800	$2.2500	$2.2100	$2.1900	$2.2250	$2.2650		$2.2300
January 28, 2016	$2.1700	$2.1800	$2.2500	$2.2100	$2.2000	$2.2100	$2.2600	$2.4850	$2.2350
January 29, 2016	$2.0600	$2.0650	$2.1250	$2.1000	$2.1050	$2.0950	$2.1500		$2.1200

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Date	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Carthage Hub**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Columbia Gulf Mainline**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Transco Zone 4**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Sonat LA**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 1**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 2**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 3**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Florida City Gates**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Henry Hub**
January 30, 2016	$2.0600	$2.0650	$2.1250	$2.1000	$2.1050	$2.0950	$2.1500		$2.1200
January 31, 2016	$2.0600	$2.0650	$2.1250	$2.1000	$2.1050	$2.0950	$2.1500		$2.1200
February 1, 2016	$2.2200	$2.2100	$2.2500	$2.2400	$2.2300	$2.2500	$2.2800	$2.4900	$2.2600
February 2, 2016	$2.0800	$2.0800	$2.1250	$2.1100	$2.0900	$2.1250	$2.1400	$2.3300	$2.1850
February 3, 2016	$1.9650	$1.9550	$2.0000	$1.9850	$1.9700	$1.9950	$2.0150	$2.1850	$2.0250
February 4, 2016	$2.0200	$1.9900	$2.0550	$2.0350	$2.0350	$2.0500	$2.0650	$2.2400	$2.0600
February 5, 2016	$1.9900	$1.9800	$2.0450	$2.0200	$2.0150	$2.0250	$2.0450	$2.2400	$2.0450
February 6, 2016	$2.0300	$2.0250	$2.1000	$2.0550	$2.0700	$2.0750	$2.1100	$2.4100	$2.0850
February 7, 2016	$2.0300	$2.0250	$2.1000	$2.0550	$2.0700	$2.0750	$2.1100	$2.4100	$2.0850
February 8, 2016	$2.0300	$2.0250	$2.1000	$2.0550	$2.0700	$2.0750	$2.1100	$2.4100	$2.0850
February 9, 2016	$2.1400	$2.1700	$2.2300	$2.2100	$2.2150	$2.2150	$2.2600	$2.8250	$2.2250
February 10, 2016	$2.1150	$2.1250	$2.1900	$2.1700	$2.1750	$2.1800	$2.2200	$2.7800	$2.1650
February 11, 2016	$2.0600	$2.0750	$2.1300	$2.1050	$2.1200	$2.1200	$2.1600	$2.9100	$2.1250
February 12, 2016	$2.0400	$2.0500	$2.1200	$2.0800		$2.1100	$2.1250		$2.1200
February 13, 2016	$1.9400	$1.9700	$2.0450	$2.0100		$2.0400	$2.0450		$2.0650
February 14, 2016	$1.9400	$1.9700	$2.0450	$2.0100		$2.0400	$2.0450		$2.0650
February 15, 2016	$1.9400	$1.9700	$2.0450	$2.0100		$2.0400	$2.0450		$2.0650
February 16, 2016	$1.9400	$1.9700	$2.0450	$2.0100		$2.0400	$2.0450		$2.0650
February 17, 2016	$1.8000	$1.8250	$1.8950	$1.8650		$1.8800	$1.9000		$1.9200
February 18, 2016	$1.8050	$1.8200	$1.8950	$1.8600		$1.8700	$1.9000		$1.9150
February 19, 2016	$1.7900	$1.8000	$1.8600	$1.8350		$1.8300	$1.8700		$1.8750
February 20, 2016	$1.7150	$1.7300	$1.7750	$1.7550	$1.7550		$1.7950		$1.8100
February 21, 2016	$1.7150	$1.7300	$1.7750	$1.7550	$1.7550		$1.7950		$1.8100
February 22, 2016	$1.7150	$1.7300	$1.7750	$1.7550	$1.7550		$1.7950		$1.8100
February 23, 2016	$1.7450	$1.7500	$1.8050	$1.7700	$1.7700	$1.8000	$1.8100		$1.8400
February 24, 2016	$1.7250	$1.7350	$1.7800	$1.7650		$1.7750	$1.7900		$1.8300
February 25, 2016	$1.7300	$1.7150	$1.7700	$1.7600	$1.7250	$1.7600	$1.7800		$1.7950
February 26, 2016	$1.7150	$1.7000	$1.7700	$1.7500	$1.7400	$1.7350	$1.7750	$1.9600	$1.7650
February 27, 2016	$1.5950	$1.5900	$1.6650	$1.6200	$1.6250	$1.6300	$1.6800		$1.6650
February 28, 2016	$1.5950	$1.5900	$1.6650	$1.6200	$1.6250	$1.6300	$1.6800		$1.6650
February 29, 2016	$1.5950	$1.5900	$1.6650	$1.6200	$1.6250	$1.6300	$1.6800		$1.6650
March 1, 2016	$1.4950	$1.5200	$1.5500	$1.5350	$1.5200	$1.5450	$1.5450		$1.6000
March 2, 2016	$1.5150	$1.5250	$1.5600	$1.5500	$1.5400	$1.5350	$1.5550	$1.7350	$1.5700
March 3, 2016	$1.5350	$1.5400	$1.5900	$1.5650	$1.5600	$1.5700	$1.5900	$1.7600	$1.5900
March 4, 2016	$1.4950	$1.5150	$1.5650	$1.5500	$1.5500	$1.5450	$1.5750	$1.7400	$1.5600
March 5, 2016	$1.4250	$1.4350	$1.5000	$1.4750		$1.4750	$1.5100	$1.6850	$1.4850
March 6, 2016	$1.4250	$1.4350	$1.5000	$1.4750		$1.4750	$1.5100	$1.6850	$1.4850
March 7, 2016	$1.4250	$1.4350	$1.5000	$1.4750		$1.4750	$1.5100	$1.6850	$1.4850
March 8, 2016	$1.4500	$1.4550	$1.5200	$1.5000		$1.4950	$1.5300	$1.6950	$1.5250
March 9, 2016	$1.5000	$1.4800	$1.5350	$1.5250		$1.5300	$1.5700		$1.5500
March 10, 2016	$1.5450	$1.5150	$1.5750	$1.5500		$1.5650	$1.6000	$1.7700	$1.5750
March 11, 2016	$1.6450	$1.6100	$1.6850	$1.6550	$1.6700	$1.6700	$1.7250		$1.6950

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Date	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Carthage Hub**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Columbia Gulf Mainline**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Transco Zone 4**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Sonat LA**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 1**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 2**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 3**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Florida City Gates**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Henry Hub**
March 12, 2016	$1.6800	$1.6550	$1.7050	$1.6900	$1.7150	$1.7450	$1.7550	$2.0000	$1.7200
March 13, 2016	$1.6800	$1.6550	$1.7050	$1.6900	$1.7150	$1.7450	$1.7550	$2.0000	$1.7200
March 14, 2016	$1.6800	$1.6550	$1.7050	$1.6900	$1.7150	$1.7450	$1.7550	$2.0000	$1.7200
March 15, 2016	$1.6850	$1.6250	$1.6650	$1.6500	$1.6700	$1.6900	$1.7350	$1.9700	$1.6850
March 16, 2016	$1.7250	$1.7250	$1.7750	$1.7450	$1.7650	$1.7900	$1.8800	$2.2450	$1.7750
March 17, 2016	$1.7050	$1.6800	$1.7350	$1.7200	$1.7300	$1.7400	$1.8350	$2.3900	$1.7400
March 18, 2016	$1.7700	$1.7700	$1.8050	$1.7800	$1.8100	$1.8200	$1.8750	$2.3050	$1.8100
March 19, 2016	$1.8000	$1.7950	$1.8500	$1.8250		$1.8400	$1.9000	$2.1300	$1.8400
March 20, 2016	$1.8000	$1.7950	$1.8500	$1.8250		$1.8400	$1.9000	$2.1300	$1.8400
March 21, 2016	$1.8000	$1.7950	$1.8500	$1.8250		$1.8400	$1.9000	$2.1300	$1.8400
March 22, 2016	$1.7150	$1.7200	$1.7500	$1.7600	$1.7500	$1.7650	$1.8250		$1.7600
March 23, 2016	$1.7200	$1.7050	$1.7450	$1.7400	$1.7400	$1.7600	$1.7700	$2.0400	$1.7550
March 24, 2016	$1.7550	$1.7550	$1.7900	$1.7950	$1.7950	$1.8000	$1.8650	$2.0950	$1.8050
March 25, 2016	$1.6700	$1.6600	$1.7250	$1.6900	$1.6800	$1.7350	$1.7800	$1.9900	$1.7300
March 26, 2016	$1.6700	$1.6600	$1.7250	$1.6900	$1.6800	$1.7350	$1.7800	$1.9900	$1.7300
March 27, 2016	$1.6700	$1.6600	$1.7250	$1.6900	$1.6800	$1.7350	$1.7800	$1.9900	$1.7300
March 28, 2016	$1.6700	$1.6600	$1.7250	$1.6900	$1.6800	$1.7350	$1.7800	$1.9900	$1.7300
March 29, 2016	$1.7200	$1.6750	$1.7350	$1.7300		$1.7250	$1.8450	$2.0100	$1.7300
March 30, 2016	$1.7400	$1.7200	$1.7600	$1.7600	$1.7600	$1.7700	$1.8800	$2.3650	$1.7650
March 31, 2016	$1.8100	$1.7800	$1.8300	$1.8300	$1.8350	$1.8350	$1.9300	$2.3600	$1.8350
April 1, 2016	$1.8600	$1.8600	$1.9100	$1.8550	$1.8850	$1.9200	$1.9250	$2.2400	$1.9250
April 2, 2016	$1.7800	$1.8000	$1.8250	$1.8000		$1.8500	$1.8150	$2.0600	$1.8700
April 3, 2016	$1.7800	$1.8000	$1.8250	$1.8000		$1.8500	$1.8150	$2.0600	$1.8700
April 4, 2016	$1.7800	$1.8000	$1.8250	$1.8000		$1.8500	$1.8150	$2.0600	$1.8700
April 5, 2016	$1.8450	$1.8550	$1.8950	$1.8750	$1.8600	$1.8850	$1.9050	$2.1200	$1.9400
April 6, 2016	$1.8250	$1.8400	$1.8700	$1.8450		$1.8600	$1.8750		$1.9100
April 7, 2016	$1.8200	$1.8100	$1.8350	$1.8250		$1.8400	$1.8500	$2.0550	$1.8650
April 8, 2016	$1.8500	$1.8650	$1.8950	$1.8850	$1.8800	$1.8850	$1.9050	$2.1250	$1.9400
April 9, 2016	$1.8700	$1.8600	$1.8900	$1.8800		$1.8900	$1.8900	$2.1600	$1.9750
April 10, 2016	$1.8700	$1.8600	$1.8900	$1.8800		$1.8900	$1.8900	$2.1600	$1.9750
April 11, 2016	$1.8700	$1.8600	$1.8900	$1.8800		$1.8900	$1.8900	$2.1600	$1.9750
April 12, 2016	$1.7900	$1.7950	$1.8200	$1.8100	$1.8250	$1.8350	$1.8450	$2.1000	$1.8800
April 13, 2016	$1.8550	$1.8600	$1.8850	$1.8700	$1.8600	$1.8900	$1.9000	$2.2200	$1.9400
April 14, 2016	$1.8400	$1.8800	$1.8950	$1.8850	$1.8950	$1.9050	$1.9300	$2.2600	$1.9800
April 15, 2016	$1.7500	$1.7900	$1.8100	$1.8100	$1.8000	$1.8300	$1.8450	$2.0800	$1.9100
April 16, 2016	$1.5900	$1.6300	$1.6450	$1.6500	$1.6500	$1.6650	$1.6900	$1.9550	$1.7050
April 17, 2016	$1.5900	$1.6300	$1.6450	$1.6500	$1.6500	$1.6650	$1.6900	$1.9550	$1.7050
April 18, 2016	$1.5900	$1.6300	$1.6450	$1.6500	$1.6500	$1.6650	$1.6900	$1.9550	$1.7050
April 19, 2016	$1.7050	$1.7050	$1.7100	$1.7000	$1.7100	$1.7000	$1.7350	$2.0300	$1.7650
April 20, 2016	$1.8450	$1.8450	$1.8700	$1.8650	$1.8600	$1.8700	$1.8850	$2.1600	$1.9150
April 21, 2016	$1.8950	$1.8950	$1.9150	$1.9150	$1.9000	$1.9250	$1.9300	$2.2400	$2.0150
April 22, 2016	$1.8950	$1.8750	$1.8850	$1.8900	$1.9000	$1.8950	$1.9150	$2.1000	$1.9350

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Date	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Carthage Hub**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Columbia Gulf Mainline**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Transco Zone 4**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Sonat LA**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 1**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 2**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 3**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Florida City Gates**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Henry Hub**
April 23, 2016	$1.8450	$1.8650	$1.8800	$1.8750	$1.8900	$1.8800	$1.9350	$2.1800	$1.9000
April 24, 2016	$1.8450	$1.8650	$1.8800	$1.8750	$1.8900	$1.8800	$1.9350	$2.1800	$1.9000
April 25, 2016	$1.8450	$1.8650	$1.8800	$1.8750	$1.8900	$1.8800	$1.9350	$2.1800	$1.9000
April 26, 2016	$1.8800	$1.8800	$1.9000	$1.9000	$1.9300	$1.9100	$1.9350	$2.3200	$1.9700
April 27, 2016	$1.8450	$1.8600	$1.8700	$1.8650	$1.8600	$1.8650	$1.9200	$2.3250	$1.8800
April 28, 2016	$1.8450	$1.8650	$1.8800	$1.8750	$1.8650	$1.8850	$1.9400	$2.4350	$1.8800
April 29, 2016	$1.8350	$1.8500	$1.8750	$1.8750	$1.8850	$1.9000	$1.8850	$2.5200	$1.8950
April 30, 2016	$1.8350	$1.8500	$1.8750	$1.8750	$1.8850	$1.9000	$1.8850	$2.5200	$1.8950
May 1, 2016	$1.8050	$1.8200	$1.8600	$1.8600	$1.8450	$1.8650	$1.9000	$2.7200	$1.9050
May 2, 2016	$1.8050	$1.8200	$1.8600	$1.8600	$1.8450	$1.8650	$1.9000	$2.7200	$1.9050
May 3, 2016	$1.8350	$1.8200	$1.8550	$1.8550	$1.8550	$1.8750	$1.8900	$2.5950	$1.9100
May 4, 2016	$1.8750	$1.8550	$1.8900	$1.8800	$1.9000	$1.8800	$1.9050		$1.9200
May 5, 2016	$1.9400	$1.9400	$1.9700	$1.9650		$1.9750	$1.9750		$1.9950
May 6, 2016	$1.8650	$1.8750	$1.9300	$1.9050	$1.9250	$1.9350	$1.9350		$2.0350
May 7, 2016	$1.7350	$1.7500	$1.7550	$1.7550	$1.7450	$1.7200	$1.7450		$1.8400
May 8, 2016	$1.7350	$1.7500	$1.7550	$1.7550	$1.7450	$1.7200	$1.7450		$1.8400
May 9, 2016	$1.7350	$1.7500	$1.7550	$1.7550	$1.7450	$1.7200	$1.7450		$1.8400
May 10, 2016	$1.8750	$1.8800	$1.9200	$1.9100	$1.9300	$1.9100	$1.9250	$2.3050	$1.9700
May 11, 2016	$1.9300	$1.9350	$1.9600	$1.9550		$1.9650	$1.9700	$2.5200	$2.0450
May 12, 2016	$1.9150	$1.9150	$1.9550	$1.9450	$1.9600	$1.9650	$1.9700	$2.5950	$2.0100
May 13, 2016	$1.9150	$1.9200	$1.9600	$1.9500	$1.9500	$1.9400	$1.9650	$2.4700	$2.0050
May 14, 2016	$1.8900	$1.8750	$1.9000	$1.8800	$1.8850	$1.8800	$1.9150	$2.4200	$1.9550
May 15, 2016	$1.8900	$1.8750	$1.9000	$1.8800	$1.8850	$1.8800	$1.9150	$2.4200	$1.9550
May 16, 2016	$1.8900	$1.8750	$1.9000	$1.8800	$1.8850	$1.8800	$1.9150	$2.4200	$1.9550
May 17, 2016	$1.8300	$1.8350	$1.8500	$1.8550	$1.8450	$1.8450	$1.8800	$2.2600	$1.9050
May 18, 2016	$1.8700	$1.8800	$1.9050	$1.9050	$1.9000	$1.9250	$1.9250	$2.2550	$1.9700
May 19, 2016	$1.7950	$1.8100	$1.8500	$1.8450	$1.8650	$1.8750	$1.9000	$2.2250	$1.9100
May 20, 2016	$1.7000	$1.7050	$1.7450	$1.7250	$1.7550	$1.7900	$1.8200	$2.2550	$1.8300
May 21, 2016	$1.7150	$1.7400	$1.7500	$1.7400	$1.7200	$1.7400	$1.7750	$2.1000	$1.8150
May 22, 2016	$1.7150	$1.7400	$1.7500	$1.7400	$1.7200	$1.7400	$1.7750	$2.1000	$1.8150
May 23, 2016	$1.7150	$1.7400	$1.7500	$1.7400	$1.7200	$1.7400	$1.7750	$2.1000	$1.8150
May 24, 2016	$1.8800	$1.8900	$1.9300	$1.9200	$1.9200	$1.9400	$1.9400	$2.2850	$1.9550
May 25, 2016	$1.8450	$1.8150	$1.8450	$1.8600	$1.8250	$1.8450	$1.8500	$2.1600	$1.9100
May 26, 2016	$1.7100	$1.7050	$1.7450	$1.7450	$1.7200	$1.7450	$1.7650	$2.0000	$1.7800
May 27, 2016	$1.7200	$1.7200	$1.7550	$1.7450	$1.7250	$1.7400	$1.7650	$2.0650	$1.7500
May 28, 2016	$1.8250	$1.8250	$1.8450	$1.8200	$1.8400	$1.8150	$1.8700	$2.1900	$1.7800
May 29, 2016	$1.8250	$1.8250	$1.8450	$1.8200	$1.8400	$1.8150	$1.8700	$2.1900	$1.7800
May 30, 2016	$1.8250	$1.8250	$1.8450	$1.8200	$1.8400	$1.8150	$1.8700	$2.1900	$1.7800
May 31, 2016	$1.8250	$1.8250	$1.8450	$1.8200	$1.8400	$1.8150	$1.8700	$2.1900	$1.7800
June 1, 2016	$2.0200	$2.0450	$2.0850	$2.0750	$2.0600	$2.0750	$2.1150	$2.5400	$2.0850
June 2, 2016	$2.2000	$2.2050	$2.2600	$2.2350	$2.2400	$2.2600	$2.3000	$2.8200	$2.2550
June 3, 2016	$2.2450	$2.2100	$2.2900	$2.2800	$2.2700	$2.3100	$2.3150	$2.9400	$2.3000

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Date	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Carthage Hub**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Columbia Gulf Mainline**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Transco Zone 4**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Sonat LA**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 1**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 2**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **FGT Zone 3**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Florida City Gates**	Platts Gas GD - Gas Daily Settle (USD /MMBtu) **Henry Hub**
June 4, 2016	$2.1750	$2.1950	$2.2650	$2.2450	$2.2500	$2.2800	$2.3000	$2.7700	$2.3150
June 5, 2016	$2.1750	$2.1950	$2.2650	$2.2450	$2.2500	$2.2800	$2.3000	$2.7700	$2.3150
June 6, 2016	$2.1750	$2.1950	$2.2650	$2.2450	$2.2500	$2.2800	$2.3000	$2.7700	$2.3150
June 7, 2016	$2.2200	$2.2150	$2.2750	$2.2650	$2.2450	$2.2750	$2.3200	$2.6500	$2.3250
June 8, 2016	$2.2350	$2.2050	$2.2800	$2.2600	$2.2450	$2.2600	$2.3300	$2.6400	$2.2850
June 9, 2016	$2.2600	$2.2650	$2.3300	$2.3150	$2.3000	$2.3250	$2.3750	$2.7000	$2.3300
June 10, 2016	$2.2650	$2.2550	$2.3000	$2.2850	$2.2900	$2.2950	$2.3600	$2.6150	$2.3050
June 11, 2016	$2.3750	$2.3700	$2.4150	$2.4150	$2.4000	$2.4300	$2.4500	$2.8000	$2.4150
June 12, 2016	$2.3750	$2.3700	$2.4150	$2.4150	$2.4000	$2.4300	$2.4500	$2.8000	$2.4150
June 13, 2016	$2.3750	$2.3700	$2.4150	$2.4150	$2.4000	$2.4300	$2.4500	$2.8000	$2.4150
June 14, 2016	$2.4950	$2.4700	$2.5400	$2.4950	$2.4850	$2.4950	$2.5850	$3.0900	$2.5250
June 15, 2016	$2.4900	$2.4900	$2.5400	$2.5250	$2.5200	$2.5400	$2.6100		$2.5150
June 16, 2016	$2.5350	$2.5500	$2.6150	$2.5850	$2.5700	$2.6000	$2.6500	$4.7450	$2.6200
June 17, 2016	$2.5000	$2.5250	$2.5750	$2.5600	$2.5550	$2.5800	$2.6050	$4.1900	$2.6050
June 18, 2016	$2.5500	$2.5250	$2.5900	$2.5400	$2.5350	$2.5650	$2.5900	$2.9800	$2.5800
June 19, 2016	$2.5500	$2.5250	$2.5900	$2.5400	$2.5350	$2.5650	$2.5900	$2.9800	$2.5800
June 20, 2016	$2.5500	$2.5250	$2.5900	$2.5400	$2.5350	$2.5650	$2.5900	$2.9800	$2.5800
June 21, 2016	$2.6350	$2.6500	$2.6850	$2.6550	$2.6400	$2.6700	$2.6900	$3.2300	$2.7350
June 22, 2016	$2.6750	$2.7000	$2.7450	$2.7050	$2.7100	$2.7100	$2.7400	$3.3900	$2.7600
June 23, 2016	$2.7000	$2.7100	$2.7700	$2.7350	$2.7350	$2.7450	$2.7850	$3.4050	$2.7800
June 24, 2016	$2.6000	$2.6050	$2.6750	$2.6400	$2.6450	$2.6500	$2.6850	$3.4950	$2.6800
June 25, 2016	$2.6350	$2.6050	$2.6600	$2.6300	$2.6200	$2.6500	$2.6900	$3.4450	$2.6750
June 26, 2016	$2.6350	$2.6050	$2.6600	$2.6300	$2.6200	$2.6500	$2.6900	$3.4450	$2.6750
June 27, 2016	$2.6350	$2.6050	$2.6600	$2.6300	$2.6200	$2.6500	$2.6900	$3.4450	$2.6750
June 28, 2016	$2.6750	$2.6750	$2.7100	$2.7000	$2.7000	$2.7100	$2.7200	$3.2600	$2.7600
June 29, 2016	$2.7850	$2.7800	$2.8350	$2.8000	$2.7950	$2.8150	$2.8950	$3.4050	$2.8550
June 30, 2016	$2.8600	$2.8400	$2.9050	$2.8700	$2.9100	$2.9400	$3.0050	$3.6500	$2.9300

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GULF's Response to Staff's Second Set of Interrogatories, Nos. 11-14

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 95
PARTY: STAFF – (DIRECT)
DESCRIPTION: Susan D. Ritenour (signed the affidavit)Cody Nicholson testifies about

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery) Clause with Generating Performance) Incentive Factor.)		Docket No. 160001-EI

GULF POWER COMPANY'S RESPONSES TO
STAFF'S SECOND SET OF INTERROGATORIES (NOS. 11-14)

GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned counsel, hereby submits the Company's responses to Staff's Second Set of Interrogatories (Nos. 11-14) on the following pages.

Respectfully submitted by electronic mail the 18th day of May, 2016.

JEFFREY A. STONE
Florida Bar No. 325953
RUSSELL A. BADDERS
Florida Bar No. 007455
STEVEN R. GRIFFIN
Florida Bar No. 0627569
BEGGS & LANE
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(850) 432-2451
Attorneys for Gulf Power Company

For interrogatories 11 through 14, please refer to page 4 of 23 from Exhibit CLN-1, attached to the Direct Testimony of Cody Nicholson, filed on March 16, 2016. The end of month Common Equity balance amount of $1,316,502,793 for January 2015 (Line 2) will be used as a common reference in many of these questions.

11. Is the end of month Common Equity balance amount of $1,316,502,793 for January 2015 (Line 2) a system amount or a jurisdictional amount? Explain in your response why a system (or a jurisdictional) amount is appropriate for the purpose of calculating GPIF rewards and penalties.

ANSWER:

The common equity balance amount of $1,316,502,793 is a system amount. Gulf appropriately uses a system common equity balance to calculate a system Maximum Allowed Incentive (Line 17) which is then applied to the jurisdictional factor (Line 20) to arrive at a Maximum Allowed Jurisdictional Incentive (Line 21).

12. Please identify the specific source for the end of month Common Equity balance amount of $1,316,502,793 for January 2015 (Line 2 of Page 4 from Exhibit CLN-1). If applicable, describe any and all different sources for February 2015 (Line 3) through December 2015 (Line 13) amounts.

ANSWER:

The source of the end-of-month common equity balance is the Company's books and records. Specifically, the components of common equity are common stock, other paid in capital, unappropriated retained earnings and accumulated other comprehensive income.

13. Please identify by specific schedule and line where the end of month Common Equity balance amount of $1,316,502,793 for January 2015 (Line 2 on Page 4 of CLN-1) is reported in Gulf's Earnings Surveillance Report for the same period. If this amount is not reported in Gulf's Earnings Surveillance Report for the same period, please explain why not.

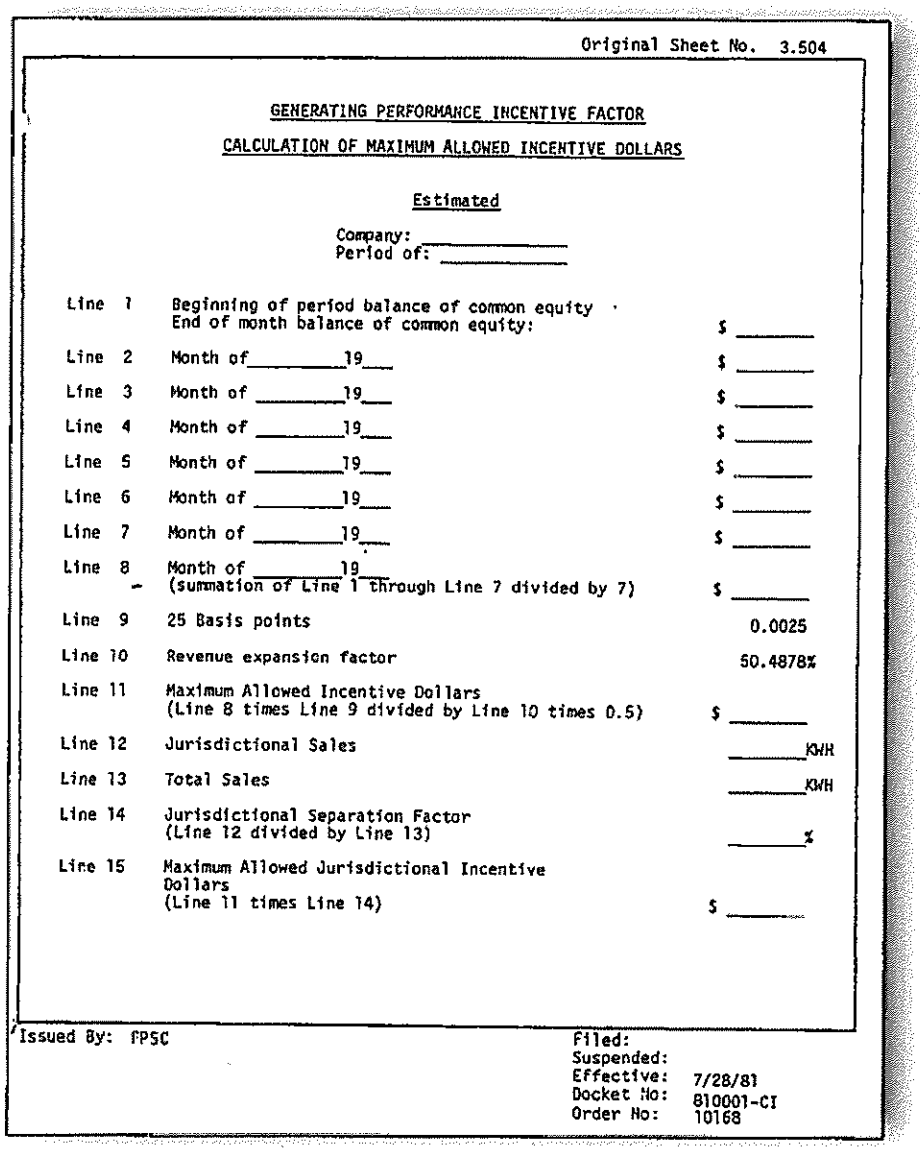
ANSWER:

The Common Equity balance amount of $1,316,502,793 is included in the system per books 13-Month average common equity on schedule 4 of Gulf's surveillance report for January 2015. Included in the system common equity balance on surveillance is a reclass, from common equity to long term debt, of accumulated other comprehensive income in the amount of $705,744.

14. For the common equity balance that Gulf used to calculate its 2015 GPIF penalty, please cite the specific order(s) and authority for using that specific common equity balance.

ANSWER:

The Commission adopted the concept of the Generating Performance Incentive Factor (GPIF) in Docket No. 800400-CI by Order No. 9558 issued September 19, 1980. A GPIF manual was created detailing how the reward/penalty should be calculated. Below is an image of a page of the GPIF manual from Order No. 10168 in Docket No. 810001-CI that shows a sample of the calculation of the reward/penalty.



Original Sheet No. 3.504

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

Estimated

Company: _____
Period of: _____

Line 1	Beginning of period balance of common equity End of month balance of common equity:	$ _____
Line 2	Month of _____19___	$ _____
Line 3	Month of _____19___	$ _____
Line 4	Month of _____19___	$ _____
Line 5	Month of _____19___	$ _____
Line 6	Month of _____19___	$ _____
Line 7	Month of _____19___	$ _____
Line 8	Month of _____19___ (summation of Line 1 through Line 7 divided by 7)	$ _____
Line 9	25 Basis points	0.0025
Line 10	Revenue expansion factor	50.4878%
Line 11	Maximum Allowed Incentive Dollars (Line 8 times Line 9 divided by Line 10 times 0.5)	$ _____
Line 12	Jurisdictional Sales	_____KWH
Line 13	Total Sales	_____KWH
Line 14	Jurisdictional Separation Factor (Line 12 divided by Line 13)	_____%
Line 15	Maximum Allowed Jurisdictional Incentive Dollars (Line 11 times Line 14)	$ _____

Issued By: FPSC

Filed:
Suspended:
Effective: 7/28/81
Docket No: 810001-CI
Order No: 10168

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 160001-EI

Before me the undersigned authority, personally appeared Susan D. Ritenour, Corporate Secretary, Treasurer, and Corporate Planning Manager of Gulf Power Company, and who on behalf of said corporation, being first duly sworn, deposes, and says that pursuant to Rule 1.340(a), Florida Rules of Civil Procedure, she verifies that the foregoing answers to the interrogatories are submitted on behalf of said corporation, and that the foregoing constitute true and correct answers to the best of her knowledge, information, and belief based on the information provided by others in the course of business. She is personally known to me.

Susan D. Ritenour
Corporate Secretary, Treasurer and
Corporate Planning Manager

Sworn to and subscribed before me this 17th day of May, 2016.

Melissa Darnes
Notary Public, State of Florida at Large

MELISSA DARNES
MY COMMISSION # FF 912698
EXPIRES: December 17, 2019
Bonded Thru Budget Notary Services

96

GULF's Response to Staff's Third Set of Interrogatories, No. 15

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 96
PARTY: STAFF – (DIRECT)
DESCRIPTION: Susan D. Ritenour (signed the affidavit)H.R. Ball testifies about Issues

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery) Clause with Generating Performance) Incentive Factor.)		Docket No. 160001-EI

GULF POWER COMPANY'S RESPONSES TO
STAFF'S THIRD SET OF INTERROGATORIES (NO. 15)

GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned counsel, hereby submits the Company's responses to Staff's Third Set of Interrogatories (No. 15) on the following pages.

Respectfully submitted by electronic mail the 29th day of August, 2016.

JEFFREY A. STONE
Florida Bar No. 325953
RUSSELL A. BADDERS
Florida Bar No. 007455
STEVEN R. GRIFFIN
Florida Bar No. 0627569
BEGGS & LANE
P. O. Box 12950
Pensacola FL 32591-2950
(850) 432-2451
Attorneys for Gulf Power Company

15. For the purpose of this interrogatory, please complete Table 1 below:

Table 1

Monthly Percent of Natural Gas Volume Hedged in Relation to Total Burned Gulf - 2013-2016				
	2013	**2014**	**2015**	**2016**
January				
February				
March				
April				
May				
June				
July				
August				
September				
October				
November				
December				
Yearly Average				
Hedging Range for Natural Gas identified in that year's Risk Management Plan				

ANSWER:

Monthly Percent of Natural Gas Volume Hedged in Relation to Total Burned Gulf - 2013-2016				
	2013	**2014**	**2015**	**2016**
January	57.90%	65.34%	64.32%	59.23%
February	53.19%	83.78%	65.60%	59.32%
March	43.53%	56.12%	123.96%	41.63%
April	46.74%	45.36%	69.28%	52.44%
May	42.16%	48.90%	55.22%	49.82%
June	72.66%	62.64%	55.72%	53.73%
July	71.90%	70.95%	48.54%	49.13%
August	61.39%	58.93%	48.77%	N/A
September	81.54%	56.21%	50.65%	N/A
October	34.94%	47.69%	40.85%	N/A
November	49.37%	57.46%	74.46%	N/A
December	60.61%	58.20%	53.27%	N/A
Yearly Average	56.17%	59.30%	57.97%	51.65%
Hedging Range for Natural Gas identified in that year's Risk Management Plan	40-60%	40-60%	40-60%	40-60%

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 160001-EI

Before me the undersigned authority, personally appeared Susan D. Ritenour, Corporate Secretary, Treasurer, and Corporate Planning Manager of Gulf Power Company, and who on behalf of said corporation, being first duly sworn, deposes, and says that pursuant to Rule 1.340(a), Florida Rules of Civil Procedure, she verifies that the foregoing answers to the interrogatories are submitted on behalf of said corporation, and that the foregoing constitute true and correct answers to the best of her knowledge, information, and belief based on the information provided by others in the course of business. She is personally known to me.

Susan D Ritenour

Susan D. Ritenour
Corporate Secretary, Treasurer and
Corporate Planning Manager

Sworn to and subscribed before me this 26th day of August, 2016.

Melissa Darnes

Notary Public, State of Florida at Large

MELISSA DARNES
MY COMMISSION # FF 912698
EXPIRES: December 17, 2019
Bonded Thru Budget Notary Services

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GULF's Response to Staff's Fourth Set of Interrogatories, Nos. 16-23

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 97
PARTY: STAFF – (DIRECT)
DESCRIPTION: Susan D. Ritenour (signed the affidavit)H.R. Ball testifies about Issues 1A, 1B, and 5B)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor.	)))	Docket No. 160001-EI

GULF POWER COMPANY'S RESPONSES TO
STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 16-23)

GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned counsel, hereby submits the Company's responses to Staff's Fourth Set of Interrogatories (Nos. 16-23) on the following pages.

Respectfully submitted by electronic mail the 1st day of September, 2016.

JEFFREY A. STONE
Florida Bar No. 325953
RUSSELL A. BADDERS
Florida Bar No. 007455
STEVEN R. GRIFFIN
Florida Bar No. 0627569
BEGGS & LANE
P. O. Box 12950
Pensacola FL 32591-2950
(850) 432-2451
Attorneys for Gulf Power Company

For purpose of the Interrogatory Numbers 16-22, please refer to the following:

A. Attachment B, Components of A Utility's Fuel Procurement Risk Management Plan, Exhibit TFB-4 attached to Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI ("TFB-4").

B. Gulf Power Company's Risk Management Plan for 2017, filed on August 4, 2016, in Docket No. 160001-EI (Gulf's 2017 Plan").

16. TFB-4 (sub-part 1) indicates that a Fuel Procurement Risk Management Plan should include information identifying the overall quantitative and qualitative risk management objectives. Please identify by page and line reference(s) where this is addressed in Gulf's 2017 Plan.

ANSWER:

Page 4 lines 21-23, pages 5 and 6 (all lines), page 7 lines 1-7, page 9 lines 18-25, page 10 (all lines), page 11 lines 1-16, page 12 lines 10-14, page 12 lines 24-25, page 13 lines 1-2 and lines 7-15, page 14 lines 22-26, page 15 lines 1-8, page 18 lines 8-14, pages 37-40 (all lines).

17. TFB-4 (sub-part 2) indicates that a Fuel Procurement Risk Management Plan should include information regarding identifying the minimum quantity of fuel to be hedged. Please identify by page and line reference(s) where this is addressed in Gulf's 2017 Plan.

ANSWER:

Page 15 lines 6-8

18. TFB-4 (sub-part 3) indicates that a Fuel Procurement Risk Management Plan should include information identifying and quantifying the general and specific risks a utility may encounter with its fuel procurement. Please identify by page and line reference(s) where this is addressed in Gulf's 2017 Plan.

ANSWER:

Page 6 lines 16-19, page 9 lines 18-21, page 12 lines 10-14 and 24-25, page 13 lines 1-2 and 19-25, page 14 lines 1-2, page 17 lines 10-17, page 28 lines 20-24, page 29 lines 1-20, page 30 lines 6-15.

19. TFB-4 (sub-part 4) indicates that a Fuel Procurement Risk Management Plan should include information describing the oversight of a utility's fuel procurement activities. Please identify by page and line reference(s) where this is addressed in Gulf's 2017 Plan.

ANSWER:

Page 18 lines 21-26, page 19 and 20 (all lines), page 23 lines 1-15, page 25 lines 19-25, page 35 (all lines), pages 43-46 (all lines), pages 50-53 (all lines).

20. TFB-4 (sub-part 6) indicates that a Fuel Procurement Risk Management Plan should include information describing the utility's corporate risk policy regarding fuel procurement activities. Please identify by page and line reference(s) where this is addressed in Gulf's 2017 Plan.

ANSWER:

Pages 18-65 (all lines).

21. TFB-4 (sub-part 8) indicates that a Fuel Procurement Risk Management Plan should describe a utility's strategy to fulfill its risk management objectives. Please identify by page and line reference(s) where this is addressed in Gulf's 2017 Plan.

ANSWER:

Page 4 lines 21-23, page 5 - 7 (all lines), page 9 lines 18-25, pages 10-11 (all lines), page 13 lines 4-25, pages 14-16 (all lines), page 17 lines 11-22, pages 37-40 (all lines).

22. TFB-4 (sub-part 13) indicates that a Fuel Procurement Risk Management Plan should include information describing a utility's reporting system for fuel procurement activities.
    a. Please identify by page and line reference(s) where this is addressed in Gulf's 2017 Plan.
    b. TFB-4 (sub-part 14) indicates that a utility's reporting system for fuel procurement activities should consistently and comprehensively identify all forms of risk associated with fuel procurement activities. Please state by page and line reference(s) where risk identification within the utility's reporting system is addressed in Gulf's 2017 Plan.
    c. TFB-4 (sub-part 14) indicates that a utility's reporting system for fuel procurement activities should consistently and comprehensively measure all forms of risk associated with fuel procurement activities. Please state by page and line reference(s) where risk measurement within the utility's reporting system is addressed in Gulf's 2017 Plan.
    d. TFB-4 (sub-part 14) indicates that a utility's reporting system for fuel procurement activities should consistently and comprehensively monitor all forms of risk associated with fuel procurement activities. Please state by page and line reference(s) where risk monitoring within the utility's reporting system is addressed in Gulf's 2017 Plan.

ANSWER:

a. Page 32 (all lines), page 33 lines 1-20, page 34 lines 6-15.

b. Page 34 lines 6-15

c. Page 34 lines 6-15

d. Page 34 lines 6-15

23. Are the processes and practices for hedging natural gas prices that Gulf follows the same processes and practices that are followed by any and all unregulated parent or affiliated companies? Discuss in your response how and why the processes and practices for hedging natural gas prices are alike, or different, between Gulf, the regulated entity, and any and all unregulated parent or affiliated companies.

ANSWER:

In accordance with the Southern Company's Separation Protocol, which complies with FERC directives to separate operations of its regulated and unregulated affiliates, details of the unregulated affiliate hedging program cannot be shared with the regulated affiliates or its agent, Southern Company Services (SCS).

SCS does not provide strategic input or recommendations to the unregulated affiliate regarding its hedging program. SCS executes natural gas hedges for Southern's regulated and unregulated affiliates according to directions provided by each individual affiliated operating company.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 160001-EI

Before me the undersigned authority, personally appeared Susan D. Ritenour, Corporate Secretary, Treasurer, and Corporate Planning Manager of Gulf Power Company, and who on behalf of said corporation, being first duly sworn, deposes, and says that pursuant to Rule 1.340(a), Florida Rules of Civil Procedure, she verifies that the foregoing answers to the interrogatories are submitted on behalf of said corporation, and that the foregoing constitute true and correct answers to the best of her knowledge, information, and belief based on the information provided by others in the course of business. She is personally known to me.

Susan D Ritenour

Susan D. Ritenour
Corporate Secretary, Treasurer and
Corporate Planning Manager

Sworn to and subscribed before me this 31st day of August, 2016.

Melissa Darnes

Notary Public, State of Florida at Large

MELISSA DARNES
MY COMMISSION # FF 912698
EXPIRES: December 17, 2019
Bonded Thru Budget Notary Services

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GULF's Response to Staff's Fifth Set of Interrogatories, Nos. 24-29

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 98
PARTY: STAFF – (DIRECT)
DESCRIPTION: Susan D. Ritenour (signed the affidavit)H.R. Ball testifies about Issues 1A, 1B, and

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery) Clause with Generating Performance) Incentive Factor.)		Docket No. 160001-EI

GULF POWER COMPANY'S RESPONSES TO
STAFF'S FIFTH SET OF INTERROGATORIES (NOS. 24-29)

GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned counsel, hereby submits the Company's responses to Staff's Fifth Set of Interrogatories (Nos. 24-29) on the following pages.

Respectfully submitted by electronic mail the 29th day of September, 2016.

JEFFREY A. STONE
Florida Bar No. 325953
RUSSELL A. BADDERS
Florida Bar No. 007455
STEVEN R. GRIFFIN
Florida Bar No. 0627569
BEGGS & LANE
P. O. Box 12950
Pensacola FL 32591-2950
(850) 432-2451
Attorneys for Gulf Power Company

24. For realized (actual) hedging savings and costs for the twelve months beginning August 1, 2015, and ending July 31, 2016, associated with swap contracts for natural gas, please provide the following information in a schedule format:
    a. the transaction date (the date the swap was entered into) for the swap;
    b. the fixed price for the swap;
    c. the month or period in the future the swap is covering; and
    d. the corresponding NYMEX futures price for the future month or period for natural gas on the transaction date of the swap.

ANSWER:

Transaction Date	Fixed Price	Period Begin Date	Period End Date	Average NYMEX Price at Market Close ($/MMBtu)	% Difference
5/5/2011	$5.98	1/1/2015	12/31/2015	5.95	0.454%
6/3/2011	$5.92	1/1/2015	12/31/2015	5.87	0.925%
6/9/2011	$5.83	1/1/2015	12/31/2015	5.75	1.327%
8/3/2011	$5.68	1/1/2015	12/31/2015	5.66	0.326%
8/4/2011	$5.53	1/1/2015	12/31/2015	5.54	-0.165%
9/9/2011	$5.45	1/1/2015	12/31/2015	5.46	-0.159%
9/22/2011	$5.33	1/1/2015	12/31/2015	5.33	0.025%
11/10/2011	$5.09	1/1/2015	12/31/2015	5.06	0.591%
11/16/2011	$4.97	1/1/2015	12/31/2015	4.96	0.119%
11/18/2011	$4.85	1/1/2015	12/31/2015	4.90	-1.052%
12/8/2011	$4.90	1/1/2015	12/31/2015	4.90	0.087%
1/20/2012	$4.13	1/1/2015	12/31/2015	4.13	0.034%
1/26/2012	$4.24	1/1/2015	12/31/2015	4.26	-0.577%
1/31/2012	$4.21	1/1/2015	12/31/2015	4.24	-0.629%
2/28/2012	$4.29	1/1/2015	12/31/2015	4.28	0.121%
3/7/2012	$4.11	1/1/2015	12/31/2015	4.11	0.091%
3/7/2012	$4.36	1/1/2016	12/31/2016	4.34	0.363%
4/11/2012	$4.43	1/1/2016	12/31/2016	4.42	0.173%
4/11/2012	$4.17	1/1/2015	12/31/2015	4.17	0.116%

Transaction Date	Fixed Price	Period Begin Date	Period End Date	Average NYMEX Price at Market Close ($/MMBtu)	% Difference
4/19/2012	$3.98	1/1/2015	12/31/2015	3.99	-0.196%
4/19/2012	$4.21	1/1/2016	12/31/2016	4.22	-0.312%
4/25/2012	$4.15	1/1/2016	12/31/2016	4.18	-0.767%
4/25/2012	$3.94	1/1/2015	12/31/2015	3.99	-1.309%
5/8/2012	$4.29	1/1/2016	12/31/2016	4.33	-0.905%
5/10/2012	$4.15	1/1/2015	12/31/2015	4.18	-0.751%
5/29/2012	$4.11	1/1/2015	12/31/2015	4.10	0.295%
5/29/2012	$4.31	1/1/2016	12/31/2016	4.31	-0.195%
6/1/2012	$4.24	1/1/2016	12/31/2016	4.27	-0.814%
6/7/2012	$4.01	1/1/2015	12/31/2015	4.01	-0.218%
6/7/2012	$4.22	1/1/2016	12/31/2016	4.22	-0.018%
6/15/2012	$4.01	1/1/2015	12/31/2015	4.01	0.098%
6/15/2012	$4.18	1/1/2016	12/31/2016	4.18	-0.024%
6/21/2012	$4.18	1/1/2016	12/31/2016	4.18	-0.112%
6/21/2012	$4.03	1/1/2015	12/31/2015	4.02	0.226%
7/6/2012	$4.09	1/1/2015	12/31/2015	4.11	-0.386%
8/2/2012	$4.39	1/1/2016	12/31/2016	4.32	1.542%
8/2/2012	$4.19	1/1/2015	12/31/2015	4.14	1.244%
8/3/2012	$4.29	1/1/2016	12/31/2016	4.30	-0.124%
8/3/2012	$4.14	1/1/2015	12/31/2015	4.11	0.596%
8/10/2012	$4.11	6/1/2015	8/31/2015	4.09	0.440%
8/13/2012	$4.26	6/1/2016	8/31/2016	4.25	0.165%
8/13/2012	$4.16	1/1/2015	12/31/2015	4.14	0.271%
8/16/2012	$4.15	1/1/2015	12/31/2015	4.12	0.614%
8/21/2012	$4.32	1/1/2016	12/31/2016	4.34	-0.457%
8/23/2012	$4.14	1/1/2015	12/31/2015	4.14	0.056%
8/23/2012	$4.28	1/1/2016	12/31/2016	4.33	-1.255%
9/5/2012	$4.08	1/1/2015	12/31/2015	4.09	-0.318%
9/5/2012	$4.28	1/1/2016	12/31/2016	4.28	-0.167%
9/7/2012	$4.03	1/1/2015	12/31/2015	4.03	-0.064%
9/7/2012	$4.20	1/1/2016	12/31/2016	4.23	-0.754%

Transaction Date	Fixed Price	Period Begin Date	Period End Date	Average NYMEX Price at Market Close ($/MMBtu)	% Difference
10/22/2012	$4.62	1/1/2016	12/31/2016	4.58	0.971%
10/22/2012	$4.43	1/1/2015	12/31/2015	4.39	0.994%
10/24/2012	$4.40	1/1/2015	12/31/2015	4.40	0.112%
10/24/2012	$4.59	1/1/2016	12/31/2016	4.59	0.076%
11/1/2012	$4.58	1/1/2016	12/31/2016	4.60	-0.503%
11/2/2012	$4.33	1/1/2015	12/31/2015	4.31	0.487%
11/2/2012	$4.50	1/1/2016	12/31/2016	4.50	-0.048%
11/9/2012	$4.48	1/1/2016	12/31/2016	4.48	0.007%
11/26/2012	$4.48	1/1/2016	12/31/2016	4.50	-0.371%
11/26/2012	$4.34	1/1/2015	12/31/2015	4.36	-0.348%
11/29/2012	$4.28	1/1/2015	12/31/2015	4.26	0.430%
11/29/2012	$4.44	1/1/2016	12/31/2016	4.41	0.751%
11/30/2012	$4.24	1/1/2015	12/31/2015	4.23	0.187%
12/10/2012	$4.20	1/1/2015	12/31/2015	4.22	-0.510%
12/10/2012	$4.37	1/1/2016	12/31/2016	4.39	-0.658%
12/12/2012	$4.19	1/1/2015	12/31/2015	4.17	0.578%
1/9/2013	$4.18	1/1/2015	12/31/2015	4.16	0.276%
1/9/2013	$4.36	1/1/2016	12/31/2016	4.37	-0.156%
1/29/2013	$4.23	1/1/2015	12/31/2015	4.21	0.368%
1/31/2013	$4.38	1/1/2016	12/31/2016	4.41	-0.624%
2/15/2013	$4.19	1/1/2015	12/31/2015	4.19	-0.076%
2/15/2013	$4.19	1/1/2015	12/31/2015	4.19	-0.076%
3/12/2013	$4.43	2/1/2016	12/31/2016	4.42	0.204%
3/12/2013	$4.29	1/1/2015	12/31/2015	4.29	-0.210%
3/21/2013	$4.29	1/1/2015	12/31/2015	4.29	-0.082%
3/21/2013	$4.40	2/1/2016	12/31/2016	4.39	0.319%
3/28/2013	$4.35	2/1/2016	12/31/2016	4.36	-0.413%
4/5/2013	$4.40	1/1/2016	12/31/2016	4.40	-0.116%
4/8/2013	$4.29	1/1/2015	12/31/2015	4.29	0.113%
4/9/2013	$4.29	1/1/2016	12/31/2016	4.29	0.054%
4/10/2013	$4.23	1/1/2015	12/31/2015	4.21	0.382%

Transaction Date	Fixed Price	Period Begin Date	Period End Date	Average NYMEX Price at Market Close ($/MMBtu)	% Difference
4/24/2013	$4.24	5/1/2015	9/30/2015	4.21	0.594%
4/24/2013	$4.33	3/1/2016	10/31/2016	4.29	1.027%
4/26/2013	$4.28	3/1/2016	10/31/2016	4.26	0.564%
4/26/2013	$4.16	5/1/2015	9/30/2015	4.19	-0.692%
5/2/2013	$4.28	1/1/2015	12/31/2015	4.26	0.444%
5/2/2013	$4.31	1/1/2016	12/31/2016	4.30	0.120%
5/28/2013	$4.45	4/1/2016	10/31/2016	4.44	0.135%
5/30/2013	$4.27	5/1/2015	9/30/2015	4.31	-0.998%
5/30/2013	$4.50	3/1/2016	12/31/2016	4.46	0.874%
6/6/2013	$4.28	1/1/2015	12/31/2015	4.24	0.911%
6/6/2013	$4.43	1/1/2016	12/31/2016	4.40	0.737%
6/20/2013	$4.21	1/1/2015	12/31/2015	4.23	-0.316%
6/21/2013	$4.34	1/1/2016	12/31/2016	4.30	0.979%
6/25/2013	$4.19	1/1/2015	12/31/2015	4.17	0.466%
7/1/2013	$4.27	1/1/2016	12/31/2016	4.29	-0.428%
7/1/2013	$4.12	1/1/2015	12/31/2015	4.12	-0.004%
7/11/2013	$4.18	1/1/2015	12/31/2015	4.17	0.140%
7/19/2013	$4.29	1/1/2016	12/31/2016	4.30	-0.279%
7/26/2013	$4.26	1/1/2016	12/31/2016	4.25	0.312%
7/26/2013	$4.14	1/1/2015	12/31/2015	4.13	0.131%
7/30/2013	$4.22	1/1/2016	12/31/2016	4.21	0.243%
7/30/2013	$4.07	1/1/2015	12/31/2015	4.07	-0.100%
8/7/2013	$3.99	1/1/2015	12/31/2015	3.97	0.329%
8/7/2013	$4.14	1/1/2016	12/31/2016	4.15	-0.317%
8/29/2013	$4.11	1/1/2015	12/31/2015	4.14	-0.899%
9/10/2013	$4.20	1/1/2016	12/31/2016	4.21	-0.364%
9/11/2013	$4.06	1/1/2015	12/31/2015	4.07	-0.364%
9/24/2013	$4.07	1/1/2015	12/31/2015	4.06	0.181%
10/21/2013	$4.12	1/1/2015	12/31/2015	4.09	0.828%
10/21/2013	$4.19	1/1/2016	12/31/2016	4.18	0.169%
10/22/2013	$3.98	6/1/2015	9/30/2015	3.97	0.176%

Transaction Date	Fixed Price	Period Begin Date	Period End Date	Average NYMEX Price at Market Close ($/MMBtu)	% Difference
10/28/2013	$3.97	7/1/2015	9/30/2015	3.95	0.431%
10/28/2013	$4.14	1/1/2016	12/31/2016	4.13	0.254%
10/29/2013	$3.99	1/1/2015	12/31/2015	3.99	-0.163%
10/31/2013	$4.09	1/1/2016	12/31/2016	4.07	0.415%
10/31/2013	$3.96	1/1/2015	12/31/2015	3.94	0.399%
11/4/2013	$3.83	1/1/2015	12/31/2015	3.84	-0.213%
11/4/2013	$3.98	1/1/2016	12/31/2016	3.98	0.033%
12/12/2013	$4.15	1/1/2016	12/31/2016	4.16	-0.206%
1/9/2014	$4.10	1/1/2016	12/31/2016	4.04	1.611%
1/24/2014	$4.13	1/1/2016	12/31/2016	4.12	0.057%
1/24/2014	$4.15	1/1/2015	12/31/2015	4.18	-0.772%
1/30/2014	$4.00	4/1/2015	8/31/2015	3.96	0.960%
2/4/2014	$4.24	12/1/2015	12/31/2015	4.25	-0.353%
2/19/2014	$4.05	5/1/2015	12/31/2015	4.04	0.173%
3/18/2014	$4.19	1/1/2016	12/31/2016	4.18	0.269%
3/31/2014	$4.19	1/1/2016	12/31/2016	4.15	0.972%
4/1/2014	$4.18	1/1/2015	12/31/2015	4.16	0.598%
5/12/2014	$4.05	1/1/2016	12/31/2016	4.22	-4.015%
5/12/2014	$4.05	1/1/2015	12/31/2015	4.22	-4.138%
5/22/2014	$3.99	1/1/2015	12/31/2015	4.17	-4.229%
6/23/2014	$4.05	1/1/2016	12/31/2016	4.25	-4.764%
6/23/2014	$4.05	1/1/2016	12/31/2016	4.25	-4.764%
6/26/2014	$4.05	1/1/2015	12/31/2015	4.22	-4.002%
6/26/2014	$4.03	1/1/2015	12/31/2015	4.22	-4.476%
7/9/2014	$4.00	5/1/2015	9/30/2015	3.99	0.075%
9/3/2014	$4.05	1/1/2016	12/31/2016	4.04	0.004%
10/1/2014	$3.96	4/1/2016	10/31/2016	3.94	0.482%
10/6/2014	$4.00	1/1/2016	12/31/2016	3.99	0.127%
10/20/2014	$3.94	1/1/2016	11/30/2016	3.91	0.684%
11/5/2014	$3.99	1/1/2016	12/31/2016	3.98	0.314%
12/4/2014	$3.93	1/1/2016	3/31/2016	3.89	0.978%

Transaction Date	Fixed Price	Period Begin Date	Period End Date	Average NYMEX Price at Market Close ($/MMBtu)	% Difference
12/4/2014	$3.72	6/1/2016	8/31/2016	3.71	0.216%
12/31/2014	$3.55	1/1/2016	3/31/2016	3.52	0.825%
1/29/2015	$3.33	1/1/2016	12/31/2016	3.29	1.147%
3/3/2015	$3.20	1/1/2016	12/31/2016	3.20	-0.296%
3/27/2015	$3.15	1/1/2016	12/31/2016	3.11	1.227%
4/10/2015	$3.07	1/1/2016	12/31/2016	3.04	0.885%
8/18/2015	$3.05	1/1/2016	12/31/2016	3.03	0.707%
8/21/2015	$3.00	1/1/2016	12/31/2016	2.98	0.537%
8/25/2015	$2.95	1/1/2016	12/31/2016	2.94	0.337%
9/21/2015	$2.89	1/1/2016	12/31/2016	2.87	0.692%
9/30/2015	$2.84	1/1/2016	12/31/2016	2.80	1.082%
10/21/2015	$2.77	1/1/2016	12/31/2016	2.76	0.487%
12/2/2015	$2.41	1/1/2016	12/31/2016	2.40	0.038%
12/23/2015	$4.05	1/1/2016	12/31/2016	4.22	-4.006%
12/23/2015	$4.03	1/1/2016	12/31/2016	4.22	-4.570%
12/23/2015	$3.99	1/1/2016	12/31/2016	4.19	-4.773%
12/23/2015	$4.05	1/1/2016	12/31/2016	4.22	-4.097%

25. For interrogatory 24 above, please explain the difference, if any, between the swap fixed price and the corresponding futures or forward price for the future period (the period being hedged) that is greater than 5 percent of the swap fixed price.

ANSWER:

There are no swap deals with a difference between the fixed price and the forward price that is greater than 5 percent.

26. For realized (actual) hedging savings and costs for the twelve months beginning August 1, 2015, and ending July 31, 2016, associated with options for natural gas prices, please provide the following information in a schedule format.
    a. the transaction date for the option;
    b. the option price or premium;
    c. the type of option;
    d. the time to expiration; and
    e. the corresponding futures price, forward price, or comparable market price for the period on the transaction date of the option.

ANSWER:

Gulf had no option transactions during the period.

27. For interrogatory 26 above, please explain the difference, if any, between the option price and the corresponding futures price, forward price, or comparable market price for the future period (the period being hedged) that is greater than 5 percent of the option price.

ANSWER:

Not applicable.

28. For open hedging transactions since August 1, 2015, has Gulf experienced any defaults by a counter-party? If yes, please identify the counter-party and explain.

ANSWER:

No.

29. Does Gulf use firm gas storage for physically hedging the price of natural gas? Please explain your response.

ANSWER:

No. Gulf does not use its firm gas storage for physically hedging the price of natural gas. Gulf uses its firm gas storage to enhance system reliability by providing protection from supply disruptions caused by events such as hurricanes, pipeline problems, or wellhead freeze-offs. Storage is also used to assist in managing daily natural gas supply and demand fluctuations at its generating facilities.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 160001-EI

Before me the undersigned authority, personally appeared Susan D. Ritenour, Corporate Secretary, Treasurer, and Corporate Planning Manager of Gulf Power Company, and who on behalf of said corporation, being first duly sworn, deposes, and says that pursuant to Rule 1.340(a), Florida Rules of Civil Procedure, she verifies that the foregoing answers to the interrogatories are submitted on behalf of said corporation, and that the foregoing constitute true and correct answers to the best of her knowledge, information, and belief based on the information provided by others in the course of business. She is personally known to me.

Susan D. Ritenour
Corporate Secretary, Treasurer and
Corporate Planning Manager

Sworn to and subscribed before me this 28th day of September, 2016.

Melissa Darnes
Notary Public, State of Florida at Large

MELISSA DARNES
MY COMMISSION # FF 912698
EXPIRES: December 17, 2019
Bonded Thru Budget Notary Services

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TECO's Response to Staff's Second Set of Interrogatories, Nos. 12-14

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 99
PARTY: STAFF – (DIRECT)
DESCRIPTION: Penelope A. Rusk

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	))))	DOCKET NO. 160001-EI FILED: May 18, 2016

TAMPA ELECTRIC COMPANY'S

ANSWERS TO SECOND SET OF INTERROGATORIES (NOS. 12-14)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (Nos. 12-14) propounded and served on April 18, 2016 by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 160001-EI
INDEX TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 12-14)

Number	Witness	Subject	Bates Stamped Page
1	Buckley	Is the end of month Common Equity balance amount of C (Line 2) a system amount or a jurisdictional amount? Explain in your response why a system (or a jurisdictional) amount is appropriate for the purpose of calculating GPIF rewards and penalties.	1
2	Buckley	Please identify the specific source for the end of month Common Equity balance amount of $2,127,180,507 for January 2015 (Line 2)? If applicable, describe any and all different sources for February 2015 (Line 3) through December 2015 (Line 13) amounts.	2
3	Buckley	For the common equity balance that TECO used to calculate its 2015 GPIF reward, please cite the specific order(s) and authority for using that specific common equity balance.	3

Brian Buckley
Manager, Strategy &Compliance

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

For interrogatories 12 through 14, please refer to page 3 of 32 from Exhibit BSB-1, attached to the Direct Testimony of Brian S. Buckley, filed on March 16, 2016. The end of month Common Equity balance amount of $2,127,180,507 for January 2015 (Line 2) will be used as a common reference in many of these questions.

12. Is the end of month Common Equity balance amount of C (Line 2) a system amount or a jurisdictional amount? Explain in your response why a system (or a jurisdictional) amount is appropriate for the purpose of calculating GPIF rewards and penalties.

A. Tampa Electric utilizes a jurisdictional amount for the purpose of calculating GPIF rewards and penalties. The calculation of the maximum allowed jurisdictional incentive begins with system common equity balances such as the referenced January 2015 amount, and the jurisdictional separation factor is applied on Lines 18 through 21 of Exhibit BSB-1, Page 3 of 32, attached to the March 16, 2016 Direct Testimony of Brian S. Buckley. The jurisdictional amount arrived at on Line 21 is used in the calculation of GPIF rewards and penalties, subject to the additional constraint of being less than or equal to 50 percent of fuel savings.

Tampa Electric's calculations are prescribed by the GPIF Manual attached to and approved in Order No. 10168 ("Order 10168") issued in Docket No. 810001-CI on July 28, 1981, as shown on Sheet No. 3.516 (Order at page 41).

The use of system common equity balances in this calculation is appropriate because the jurisdictional separation factor is applied to the maximum incentive value on Line 21, putting the maximum allowed GPIF incentive amount on a retail jurisdictional basis.

13. Please identify the specific source for the end of month Common Equity balance amount of $2,127,180,507 for January 2015 (Line 2)? If applicable, describe any and all different sources for February 2015 (Line 3) through December 2015 (Line 13) amounts.

A. The $2,127,180,507 January 2015 Common Equity balance is taken from the Tampa Electric Surveillance Report. It can be found on Schedule 4 of the Year End section in the System Per Books column. The February 2015 through December 2015 Common Equity balances are also taken from the 2015 Surveillance Reports for the months of February to December.

14. For the common equity balance that TECO used to calculate its 2015 GPIF reward, please cite the specific order(s) and authority for using that specific common equity balance.

A. See the company's response to Interrogatory No. 12.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is Manager, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Second Set of Interrogatories, (Nos. 12-14) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 13TH day of May, 2016.

Penelope Rusk

Sworn to and subscribed before me this 13TH day of May, 2016.

Notary Public State of Florida
Tison C Vega
My Commission FF 955624
Expires 02/01/2020

My Commission expires

100

TECO's Response to Staff's Fourth Set of Interrogatories, No. 17 (Redacted)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 100
PARTY: STAFF – (DIRECT)
DESCRIPTION: Penelope A. Rusk

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	))))	DOCKET NO. 160001-EI FILED: AUGUST 29, 2016

REDACTED

TAMPA ELECTRIC COMPANY'S

ANSWERS TO FOURTH SET OF INTERROGATORIES (NO. 17)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (No. 17) propounded and served on July 29, 2016 by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 160001-EI
INDEX TO STAFF'S FOURTH SET OF INTERROGATORIES (NO. 17)

Number	Witness	Subject	Bates Stamped Page
17	Caldwell	For the purpose of this interrogatory, please complete Table 1 below:	1

Brent Caldwell
Director, Fuel Planning and Services

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

17. For the purpose of this interrogatory, please complete Table 1 below:

Table 1

Monthly Percent of Natural Gas Volume Hedged in Relation to Total Burned TECO 2013-2016				
	2013	2014	2015	2016
January				
February				
March				
April				
May				
June				
July				
August				N/A
September				N/A
October				N/A
November				N/A
December				N/A
Yearly Average				N/A
Hedging Range for Natural Gas identified in that year's Risk Management Plan				

A. Please see the table below for the monthly percentage of natural gas hedged from 2013 through present.

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 160001-EI
STAFF'S FOURTH SET OF
INTERROGATORIES
INTERROGATORY NO. 17
PAGE 2 OF 2
FILED: AUGUST 29, 2016

Monthly Percent of Natural Gas Volume Hedged in Relation to Total Burned TECO 2013-2016				
	2013	2014	2015	2016
January	53	[redacted]	[redacted]	[redacted]
February	52			
March	6			
April	78			
May	71			
June	62			
July	81			
August	62			N/A
September	72			N/A
October	70			N/A
November	66			N/A
December	79			N/A
Yearly Average	67			N/A
Hedging Range for Natural Gas identified in that year's Risk Management Plan	[redacted]			

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 Manager, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Fourth Set of Interrogatories, (No. 17) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 26th day of August, 2016.

Penelope Rusk

Sworn to and subscribed before me this 26th day of August, 2016.

Notary Public State of Florida
Tison C Vega
My Commission FF 955624
Expires 02/01/2020

My Commission expires _____

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TECO's Response to Staff's Fourth Set of Interrogatories, No. 17 (Confidential DN 07105-16)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 101
PARTY: STAFF – (DIRECT)
DESCRIPTION: Penelope A. Rusk

102

TECO's Response to Staff's Fifth Set of Interrogatories, Nos. 18, 19 (Redacted), 20-24, 25-27 (Redacted), 28

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 102
PARTY: STAFF – (DIRECT)
DESCRIPTION: Penelope A. Rusk

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	))))	DOCKET NO. 160001-EI FILED: SEPTEMBER 1, 2016

REDACTED

TAMPA ELECTRIC COMPANY'S

ANSWERS TO FIFTH SET OF INTERROGATORIES (NOS. 18-28)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (Nos. 18-28) propounded and served on August 12, 2016 by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 160001-EI
INDEX TO STAFF'S FIFTH SET OF INTERROGATORIES (NOS. 18-28)

Number	Witness	Subject	Bates Stamped Page
18	Caldwell	TFB-4 (sub-part 1) indicates that a Fuel Procurement Risk Management Plan should include information identifying the overall quantitative and qualitative risk management objectives. Please identify by page and line reference(s) where this is addressed in TECO's 2017 Plan.	1
19	Caldwell	TFB-4 (sub-part 2) indicates that a Fuel Procurement Risk Management Plan should include information regarding identifying the minimum quantity of fuel to be hedged. Please identify by page and line reference(s) where this is addressed in TECO's 2017 Plan.	2
20	Caldwell	TFB-4 (sub-part 3) indicates that a Fuel Procurement Risk Management Plan should include information identifying and quantifying the general and specific risks a utility may encounter with its fuel procurement. Please identify by page and line reference(s) where this is addressed in TECO's 2017 Plan.	3
21	Caldwell	TFB-4 (sub-part 4) indicates that a Fuel Procurement Risk Management Plan should include information describing the oversight of a utility's fuel procurement activities. Please identify by page and line reference(s) where this is addressed in TECO's 2017 Plan.	4
22	Caldwell	TFB-4 (sub-part 6) indicates that a Fuel Procurement Risk Management Plan should include information describing the utility's corporate risk policy regarding fuel procurement activities. Please identify by page and line reference(s) where this is addressed in TECO's 2017 Plan.	5
23	Caldwell	TFB-4 (sub-part 8) indicates that a Fuel Procurement Risk Management Plan should describe a utility's strategy to fulfill its risk management objectives. Please identify by page and line reference(s) where this is addressed in TECO's 2017 Plan.	6

24	Caldwell	TFB-4 (sub-part 13) indicates that a Fuel Procurement Risk Management Plan should include information describing a utility's reporting system for fuel procurement activities. a. Please identify by page and line reference(s) where this is addressed in TECO's 2017 Plan. b. TFB-4 (sub-part 14) indicates that a utility's reporting system for fuel procurement activities should consistently and comprehensively identify all forms of risk associated with fuel procurement activities. Please state by page and line reference(s) where risk identification within the utility's reporting system is addressed in TECO's 2017 Plan. c. TFB-4 (sub-part 14) indicates that a utility's reporting system for fuel procurement activities should consistently and comprehensively measure all forms of risk associated with fuel procurement activities. Please state by page and line reference(s) where risk measurement within the utility's reporting system is addressed in TECO's 2017 Plan. d. TFB-4 (sub-part 14) indicates that a utility's reporting system for fuel procurement activities should consistently and comprehensively monitor all forms of risk associated with fuel procurement activities. Please state by page and line reference(s) where risk monitoring within the utility's reporting system is addressed in TECO's 2017 Plan.	7
25	Caldwell	For the purpose of this interrogatory, please complete Table 1 below, based on TECO's 2017 Plan:	9
26	Caldwell	For the purpose of this interrogatory, please complete Table 2 below, based on TECO's 2017 Plan:	11
27	Caldwell	For the purpose of this interrogatory, please complete Table 3 below, based on TECO's 2017 Plan:	13

28	Caldwell	Are the processes and practices for hedging natural gas prices that TECO follows the same processes and practices that are followed by any and all unregulated parent or affiliated companies? Discuss in your response how and why the processes and practices for hedging natural gas prices are alike, or different, between TECO, the regulated entity, and any and all unregulated parent or affiliated companies.	15

Brent Caldwell
Director, Fuel Planning and Services

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

For the purpose of the Interrogatory Numbers 18-27 below, please refer to the following:

A. Attachment B, Components Of A Utility's Fuel Procurement Risk Management Plan, Exhibit TFB-4, attached to Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI ("TFB-4").

B. Tampa Electric Company's Risk Management Plan for 2017, filed on August 4, 2016, in Docket No. 160001-EI ("TECO's 2017 Plan").

18. TFB-4 (sub-part 1) indicates that a Fuel Procurement Risk Management Plan should include information identifying the overall quantitative and qualitative risk management objectives. Please identify by page and line reference(s) where this is addressed in TECO's 2017 Plan.

A. Tampa Electric identified the plan's overall quantitative and qualitative risk management objectives on page 1 of Tampa Electric Company's Fuel Procurement and Wholesale Power Purchases Risk Management Plan, in Section I, "Qualitative and Quantitative Risk Management Objectives."

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 160001-EI
STAFF'S FIFTH SET OF
INTERROGATORIES
INTERROGATORY NO. 19
PAGE 1 OF 1
FILED: SEPTEMBER 1, 2016

19. TFB-4 (sub-part 2) indicates that a Fuel Procurement Risk Management Plan should include information regarding identifying the minimum quantity of fuel to be hedged. Please identify by page and line reference(s) where this is addressed in TECO's 2017 Plan.

A. The company addresses the minimum quantity of fuel to be hedged on page 2 of Tampa Electric's Fuel Procurement and Wholesale Power Purchases Risk Management Plan, Section II.B, third bullet, "Establishing the quantitative limits for operating companies within Board approved corporate risk limits" and at page 3, Section III.E. The minimum hedging values are not listed explicitly in the filed Risk Management Plan but are instead incorporated by reference to the limits approved by the Tampa Electric's Risk Authorizing Committee ("RAC"). The hedged percentages approved by the RAC are listed in the table below. Tampa Electric has also provided this confidential information to parties in response to discovery and annual audit requests.

Tampa Electric Company's Fuel Procurement and Wholesale Power Purchases Risk Management Plan

Percentage of Projected Natural Gas Consumption Hedged by Month

Months Forward	Minimum %	Maximum%
[redacted]		

20. TFB-4 (sub-part 3) indicates that a Fuel Procurement Risk Management Plan should include information identifying and quantifying the general and specific risks a utility may encounter with its fuel procurement. Please identify by page and line reference(s) where this is addressed in TECO's 2017 Plan.

A. Tampa Electric identifies and quantifies the general and specific risks it may encounter with respect to its fuel procurement on pages 4 through 6 of Tampa Electric Company's Fuel Procurement and Wholesale Power Purchases Risk Management Plan, in Section III, "Risk Assessment." The company further describes and quantifies those risks at pages 6 through 9 in Section IV, "Risk Management Strategy and Current Hedging Activity."

21. TFB-4 (sub-part 4) indicates that a Fuel Procurement Risk Management Plan should include information describing the oversight of a utility's fuel procurement activities. Please identify by page and line reference(s) where this is addressed in TECO's 2017 Plan.

A. Tampa Electric describes its oversight of fuel procurement activities on pages 1 through 4 in Section II, "Oversight & Reporting of Fuel Procurement Activities," of Tampa Electric's Fuel Procurement and Wholesale Power Purchases Risk Management Plan.

160001 Hearing Exhibits 00181

22. TFB-4 (sub-part 6) indicates that a Fuel Procurement Risk Management Plan should include information describing the utility's corporate risk policy regarding fuel procurement activities. Please identify by page and line reference(s) where this is addressed in TECO's 2017 Plan.

A. Tampa Electric describes its corporate risk policy regarding fuel procurement activities on pages 1 through 4 of Tampa Electric Company's Fuel Procurement and Wholesale Power Purchases Risk Management Plan, in Section II, "Oversight & Reporting of Fuel Procurement Activities."

23. TFB-4 (sub-part 8) indicates that a Fuel Procurement Risk Management Plan should describe a utility's strategy to fulfill its risk management objectives. Please identify by page and line reference(s) where this is addressed in TECO's 2017 Plan.

A. Tampa Electric describes its strategy to fulfill its risk management objectives on pages 6 through 9, of Tampa Electric Company's Fuel Procurement and Wholesale Power Purchases Risk Management Plan, in Section IV, "Risk Management Strategy and Current Hedging Activity."

24. TFB-4 (sub-part 13) indicates that a Fuel Procurement Risk Management Plan should include information describing a utility's reporting system for fuel procurement activities.

a. Please identify by page and line reference(s) where this is addressed in TECO's 2017 Plan.

b. TFB-4 (sub-part 14) indicates that a utility's reporting system for fuel procurement activities should consistently and comprehensively identify all forms of risk associated with fuel procurement activities. Please state by page and line reference(s) where risk identification within the utility's reporting system is addressed in TECO's 2017 Plan.

c. TFB-4 (sub-part 14) indicates that a utility's reporting system for fuel procurement activities should consistently and comprehensively measure all forms of risk associated with fuel procurement activities. Please state by page and line reference(s) where risk measurement within the utility's reporting system is addressed in TECO's 2017 Plan.

d. TFB-4 (sub-part 14) indicates that a utility's reporting system for fuel procurement activities should consistently and comprehensively monitor all forms of risk associated with fuel procurement activities. Please state by page and line reference(s) where risk monitoring within the utility's reporting system is addressed in TECO's 2017 Plan.

A. a. Tampa Electric complies with all reporting guidelines established by the corporate risk policy as described on pages 1 through 4 of Tampa Electric Company's Fuel Procurement and Wholesale Power Purchases Risk Management Plan, in Section II, "Oversight & Reporting of Fuel Procurement Activities." The requirement for Tampa Electric's Fuels Management Department to report on hedging activity at least once a month to ensure compliance with its risk management plan is listed in Section II.F. Additionally, in Section II.G, Tampa Electric describes the production and review of position and mark-to-market reports by the Director of Independent Risk Oversight.

b. See the company's response to subpart (a). Risk identification, measurement and monitoring within the utility reporting system are

covered in Tampa Electric Company's Fuel Procurement and Wholesale Power Purchases Risk Management Plan, in Section II.D through II.G.

c. See the company's response to subparts (a) and (b).

d. See the company's response to subparts (a) and (b).

25. For the purpose of this interrogatory, please complete Table 1 below, based on TECO's 2017 Plan:

Period	Min/Max Hedge Volume of Forecasted Natural Gas Burn 2017	
	Minimum Target for Period	Maximum Target for Period
January 2017		
February 2017		
March 2017		
April 2017		
May 2017		
June 2017		
July 2017		
August 2017		
September 2017		
October 2017		
November 2017		
December 2017		
Yearly Average		

A. As stated in the testimony of Tampa Electric witness J. Brent Caldwell filed in this docket on August 4, 2016, Tampa Electric did not update its 2017 Risk Management Plan in accordance with the proposal approved in Commission Order No. PSC-16-0247-PAA-EI because the Office of Public Counsel protested the order. Therefore, the company's proposed hedging targets are unchanged from the previous year's risk management plan.

Tampa Electric Company's Fuel Procurement and Wholesale Power Purchases Risk Management Plan 2017 minimum and maximum target natural gas hedged volume percentages are listed in the following table.

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 160001-EI
STAFF'S FIFTH SET OF
INTERROGATORIES
INTERROGATORY NO. 25
PAGE 2 OF 2
FILED: SEPTEMBER 1, 2016

Table 1
Tampa Electric

Period	Min/Max Hedge Volume of Forecasted Natural Gas Burn 2017	
	Minimum Target for Period	Maximum Target for Period
January 2017	[redacted]	
February 2017		
March 2017		
April 2017		
May 2017		
June 2017		
July 2017		
August 2017		
September 2017		
October 2017		
November 2017		
December 2017		
Yearly Average		

26. For the purpose of this interrogatory, please complete Table 2 below, based on TECO's 2017 Plan:

Duration	Min/Max Hedge Volume of Forecasted Natural Gas Burn 2018	
	Minimum Target for Period	Maximum Target for Period
January 2018		
February 2018		
March 2018		
April 2018		
May 2018		
June 2018		
July 2018		
August 2018		
September 2018		
October 2018		
November 2018		
December 2018		
Yearly Average		

A. If Tampa Electric's 2017 Fuel and Procurement and Wholesale Power Purchases Risk Management Plan is approved as filed on August 4, 2017, and no other changes are made to the plan, the 2018 minimum and maximum target natural gas hedge percentages will be as shown in the table below. Also see the company's response to Staff's Fifth Set of Interrogatories, Interrogatory No. 25.

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 160001-EI
STAFF'S FIFTH SET OF
INTERROGATORIES
INTERROGATORY NO. 26
PAGE 2 OF 2
FILED: SEPTEMBER 1, 2016

Table 2
Tampa Electric

Duration	Min/Max Hedge Volume of Forecasted Natural Gas Burn 2018	
	Minimum Target for Period	Maximum Target for Period
January 2018	[redacted]	
February 2018		
March 2018		
April 2018		
May 2018		
June 2018		
July 2018		
August 2018		
September 2018		
October 2018		
November 2018		
December 2018		
Yearly Average		

27. For the purpose of this interrogatory, please complete Table 3 below, based on TECO's 2017 Plan:

Duration	Min/Max Hedge Volume of Forecasted Natural Gas Burn 2019	
	Minimum Target for Period	Maximum Target for Period
January 2019		
February 2019		
March 2019		
April 2019		
May 2019		
June 2019		
July 2019		
August 2019		
September 2019		
October 2019		
November 2019		
December 2019		
Yearly Average		

A. If Tampa Electric's 2017 Fuel and Procurement and Wholesale Power Purchases Risk Management Plan is approved as filed on August 4, 2017, and no other changes are made to the plan, the 2019 minimum and maximum target natural gas hedge percentages will be as shown in the table below, once the target months are reached. However, hedging of natural gas under the plan extends for 24 months forward, and Tampa Electric will not begin to execute hedges for the first month in question, January 2019, until January 2017, when the company will begin to execute a small percentage of hedges for January 2019, with additional hedges placed as time passes.

Also see the company's response to Staff's Fifth Set of Interrogatories, Interrogatory No. 25

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 160001-EI
STAFF'S FIFTH SET OF
INTERROGATORIES
INTERROGATORY NO. 27
PAGE 2 OF 2
FILED: SEPTEMBER 1, 2016

Table 3
Tampa Electric

Duration	Min/Max Hedge Volume of Forecasted Natural Gas Burn 2019	
	Minimum Target for Period	Maximum Target for Period
January 2019	[redacted]	
February 2019		
March 2019		
April 2019		
May 2019		
June 2019		
July 2019		
August 2019		
September 2019		
October 2019		
November 2019		
December 2019		
Yearly Average		

28. Are the processes and practices for hedging natural gas prices that TECO follows the same processes and practices that are followed by any and all unregulated parent or affiliated companies? Discuss in your response how and why the processes and practices for hedging natural gas prices are alike, or different, between TECO, the regulated entity, and any and all unregulated parent or affiliated companies.

A. As stated in Tampa Electric Company's Fuel Procurement and Wholesale Power Purchases Risk Management Plan, at page 1, the corporate Energy Risk Management Policy applies to all energy commodity transacting activities at all operating companies. In addition, Tampa Electric is not aware of any unregulated parent or affiliate company engaging in natural gas price hedging activities.

160001 Hearing Exhibits 00192

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 Manager, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Fifth Set of Interrogatories, (Nos. 18-28) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 30th day of August, 2016.

Penelope Rusk

Sworn to and subscribed before me this 30TH day of August, 2016.

Notary Public State of Florida
Tison C Vega
My Commission FF 955624
Expires 02/01/2020

My Commission expires _____

103

TECO's Response to Staff's Fifth Set of Interrogatories, Nos. 19, 25-27 (Confidential DN 07257-16)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 103
PARTY: STAFF – (DIRECT)
DESCRIPTION: Penelope A. Rusk

104

TECO's Response to Staff's Sixth Set of Interrogatories, Nos. 29 (Redacted), 30-34

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 104
PARTY: STAFF – (DIRECT)
DESCRIPTION: Penelope A. Rusk

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	))))	DOCKET NO. 160001-EI FILED: SEPTEMBER 29, 2016

REDACTED

TAMPA ELECTRIC COMPANY'S

ANSWERS TO SIXTH SET OF INTERROGATORIES (NOS. 29-34)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (Nos. 29-34) propounded and served on September 9, 2016 by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 160001-EI
INDEX TO STAFF'S SIXTH SET OF INTERROGATORIES (NOS. 29-34)

Number	Witness	Subject	Bates Stamped Page
29	Caldwell	For realized (actual) hedging savings and costs for the twelve months beginning August 1, 2015, and ending July 31, 2016, associated with swap contracts for natural gas, please provide the following information in a schedule format: a. the transaction date (the date the swap was entered into) for the swap; b. the fixed price for the swap; c. the month or period in the future the swap is covering; and d. the corresponding NYMEX futures price for the future month or period for natural gas on the transaction date of the swap.	1
30	Caldwell	For interrogatory 29 above, please explain the difference, if any, between the swap fixed price and the corresponding futures or forward price for the future period (the period being hedged) that is greater than 5 percent of the swap fixed price.	7
31	Caldwell	For realized (actual) hedging savings and costs for the twelve months beginning August 1, 2015, and ending July 31, 2016, associated with options for natural gas prices, please provide the following information in a schedule format. a. the transaction date for the option; b. the option price or premium; c. the type of option; d. the time to expiration; and e. the corresponding futures price, forward price, or comparable market price for the period on the transaction date of the option.	9
32	Caldwell	For interrogatory 31 above, please explain the difference, if any, between the option price and the corresponding futures price, forward price, or comparable market price for the future period (the period being hedged) that is greater than 5 percent of the option price.	10

33	Caldwell	For open hedging transactions since August 1, 2015, has TECO experienced any defaults by a counter-party? If yes, please identify the counter-party and explain.	11
34	Caldwell	Does TECO use firm gas storage for physically hedging the price of natural gas? Please explain your response.	12

Brent Caldwell
Director, Fuel Planning and Services

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

REDACTED

29. For realized (actual) hedging savings and costs for the twelve months beginning August 1, 2015, and ending July 31, 2016, associated with swap contracts for natural gas, please provide the following information in a schedule format:

a. the transaction date (the date the swap was entered into) for the swap;
b. the fixed price for the swap;
c. the month or period in the future the swap is covering; and
d. the corresponding NYMEX futures price for the future month or period for natural gas on the transaction date of the swap.

A. The requested information is provided in the table below.

Transaction Date (a)	Fixed Price (b)	Contract Month (c)	NYMEX Forward Price (d)
2/18/14	[redacted]	Aug-15	$4.0450
8/26/13		Aug-15	$4.0750
2/5/14		Aug-15	$4.0210
2/20/14		Aug-15	$3.9940
2/18/14		Aug-15	$4.0450
2/20/14		Aug-15	$3.9940
2/13/14		Aug-15	$4.0290
2/12/14		Aug-15	$4.0310
8/23/13		Aug-15	$4.0720
1/2/15		Aug-15	$3.0850
1/5/15		Aug-15	$2.9790
2/11/15		Aug-15	$2.9470
3/19/15		Aug-15	$2.9470
5/27/15		Aug-15	$2.8650
5/27/15		Aug-15	$2.8650
2/20/14		Sep-15	$3.9770
2/20/14		Sep-15	$3.9770
5/7/14		Sep-15	$4.2240
5/8/14		Sep-15	$4.1530
9/23/13		Sep-15	$4.0650
5/7/14		Sep-15	$4.2240
9/23/13		Sep-15	$4.0650

REDACTED

Transaction Date (a)	Fixed Price (b)	Contract Month (c)	NYMEX Forward Price (d)
2/13/14	[redacted]	Sep-15	$4.0140
5/8/14		Sep-15	$4.1530
2/18/14		Sep-15	$4.0280
1/2/15		Sep-15	$3.0670
1/5/15		Sep-15	$2.9610
2/11/15		Sep-15	$2.9360
3/19/15		Sep-15	$2.9380
6/23/15		Sep-15	$2.7610
6/23/15		Sep-15	$2.7610
10/28/13		Oct-15	$3.9730
5/8/14		Oct-15	$4.1720
2/20/14		Oct-15	$3.9990
2/20/14		Oct-15	$3.9990
5/7/14		Oct-15	$4.2460
5/8/14		Oct-15	$4.1720
5/7/14		Oct-15	$4.2460
10/28/13		Oct-15	$3.9730
2/18/14		Oct-15	$4.0500
1/2/15		Oct-15	$3.0920
1/5/15		Oct-15	$2.9850
2/11/15		Oct-15	$2.9640
3/19/15		Oct-15	$2.9610
7/28/15		Oct-15	$2.8450
7/28/15		Oct-15	$2.8450
9/16/15		Oct-15	$2.6600
5/7/14		Nov-15	$4.2870
5/7/14		Nov-15	$4.2870
11/26/13		Nov-15	$4.0810
5/8/14		Nov-15	$4.2180
2/18/14		Nov-15	$4.0940
2/20/14		Nov-15	$4.0460
11/26/13		Nov-15	$4.0810
3/19/15		Nov-15	$3.0450

REDACTED

TAMPA ELECTRIC COMPANY
DOCKET NO. 160001-EI
STAFF'S SIXTH SET OF
INTERROGATORIES
INTERROGATORY NO. 29
PAGE 3 OF 6
FILED: SEPTEMBER 29, 2016

Transaction Date (a)	Fixed Price (b)	Contract Month (c)	NYMEX Forward Price (d)
8/14/15	[redacted]	Nov-15	$2.9390
9/16/15		Nov-15	$2.7390
12/26/13		Dec-15	$4.2470
12/26/13		Dec-15	$4.2470
7/14/14		Dec-15	$4.2200
2/20/14		Dec-15	$4.2150
2/20/14		Dec-15	$4.2150
2/18/14		Dec-15	$4.2540
1/5/15		Dec-15	$3.3040
3/19/15		Dec-15	$3.1930
9/16/15		Dec-15	$2.8920
1/27/14		Jan-16	$4.3010
1/27/14		Jan-16	$4.3010
2/18/14		Jan-16	$4.3960
2/20/14		Jan-16	$4.3640
7/14/14		Jan-16	$4.3460
7/28/15		Jan-16	$3.2420
9/16/15		Jan-16	$3.0000
9/18/15		Jan-16	$2.9410
10/26/15		Jan-16	$2.5150
12/18/15		Jan-16	$1.7670
2/25/14		Feb-16	$4.3680
7/14/14		Feb-16	$4.3210
7/14/14		Feb-16	$4.3210
2/20/14		Feb-16	$4.3370
2/24/15		Feb-16	$3.3310
5/27/15		Feb-16	$3.2570
5/27/15		Feb-16	$3.2570
8/14/15		Feb-16	$3.1920
8/14/15		Feb-16	$3.1920
9/16/15		Feb-16	$3.0020
9/18/15		Feb-16	$2.9420
11/23/15		Feb-16	$2.3860

REDACTED

Transaction Date (a)	Fixed Price (b)	Contract Month (c)	NYMEX Forward Price (d)
1/25/16	[redacted]	Feb-16	$2.1580
3/25/14		Mar-16	$4.3410
3/25/14		Mar-16	$4.3410
7/14/14		Mar-16	$4.2590
7/14/14		Mar-16	$4.2590
7/14/14		Mar-16	$4.2590
7/14/14		Mar-16	$4.2590
6/23/15		Mar-16	$3.1920
6/23/15		Mar-16	$3.1920
6/23/15		Mar-16	$3.1920
6/23/15		Mar-16	$3.1920
9/16/15		Mar-16	$2.9660
9/16/15		Mar-16	$2.9660
9/18/15		Mar-16	$2.9070
9/18/15		Mar-16	$2.9070
9/18/15		Mar-16	$2.9070
9/18/15		Mar-16	$2.9070
1/19/16		Mar-16	$2.1080
1/19/16		Mar-16	$2.1080
1/19/16		Mar-16	$2.1080
1/19/16		Mar-16	$2.1080
1/19/16		Mar-16	$2.1080
1/19/16		Mar-16	$2.1080
1/25/16		Mar-16	$2.1550
1/25/16		Mar-16	$2.1550
4/30/14		Apr-16	$4.1840
7/14/14		Apr-16	$4.0190
7/14/14		Apr-16	$4.0190
4/15/15		Apr-16	$2.9590
7/28/15		Apr-16	$3.0450
7/28/15		Apr-16	$3.0450
9/16/15		Apr-16	$2.8300
9/23/15		Apr-16	$2.7590

REDACTED

Transaction Date (a)	Fixed Price (b)	Contract Month (c)	NYMEX Forward Price (d)
1/19/16	[redacted]	Apr-16	$2.1770
1/19/16		Apr-16	$2.1770
1/19/16		Apr-16	$2.1770
1/25/16		Apr-16	$2.2410
1/25/16		Apr-16	$2.2410
1/25/16		Apr-16	$2.2410
5/28/14		May-16	$4.1290
5/28/14		May-16	$4.1290
7/14/14		May-16	$4.0290
7/14/14		May-16	$4.0290
5/27/15		May-16	$3.0520
8/14/15		May-16	$2.9840
8/19/15		May-16	$2.9030
9/16/15		May-16	$2.8280
9/16/15		May-16	$2.8280
9/17/15		May-16	$2.8200
9/17/15		May-16	$2.8200
1/19/16		May-16	$2.2470
1/19/16		May-16	$2.2470
2/16/16		May-16	$2.0350
2/16/16		May-16	$2.0350
2/16/16		May-16	$2.0350
2/16/16		May-16	$2.0350
2/17/16		May-16	$2.0760
7/14/14		Jun-16	$4.0550
7/14/14		Jun-16	$4.0550
6/23/14		Jun-16	$4.1470
6/23/14		Jun-16	$4.1470
6/23/15		Jun-16	$3.0790
9/16/15		Jun-16	$2.8550
9/16/15		Jun-16	$2.8550
9/17/15		Jun-16	$2.8470
9/17/15		Jun-16	$2.8470

REDACTED

Transaction Date (a)	Fixed Price (b)	Contract Month (c)	NYMEX Forward Price (d)
9/22/15	[redacted]	Jun-16	$2.7860
9/22/15		Jun-16	$2.7860
1/26/16		Jun-16	$2.3610
3/23/16		Jun-16	$1.9740
3/23/16		Jun-16	$1.9740
3/31/16		Jun-16	$2.0540
3/31/16		Jun-16	$2.0540
7/30/14		Jul-16	$3.9400
7/30/14		Jul-16	$3.9400
1/8/15		Jul-16	$3.3330
2/24/15		Jul-16	$3.1960
7/28/15		Jul-16	$3.0990
7/28/15		Jul-16	$3.0990
9/16/15		Jul-16	$2.8880
9/16/15		Jul-16	$2.8880
9/17/15		Jul-16	$2.8810
9/17/15		Jul-16	$2.8810
9/22/15		Jul-16	$2.8210
9/22/15		Jul-16	$2.8210
4/25/16		Jul-16	$2.3110
4/25/16		Jul-16	$2.3110
4/26/16		Jul-16	$2.2940
4/26/16		Jul-16	$2.2940

30. For interrogatory 29 above, please explain the difference, if any, between the swap fixed price and the corresponding futures or forward price for the future period (the period being hedged) that is greater than 5 percent of the swap fixed price.

A. Tampa Electric did not execute any swap contracts where the difference between the swap fixed price and corresponding forward price is greater than five percent of the swap fixed price.

31. For realized (actual) hedging savings and costs for the twelve months beginning August 1, 2015, and ending July 31, 2016, associated with options for natural gas prices, please provide the following information in a schedule format.

a. the transaction date for the option;
b. the option price or premium;
c. the type of option;
d. the time to expiration; and
e. the corresponding futures price, forward price, or comparable market price for the period on the transaction date of the option.

A. Tampa Electric did not use options to hedge natural gas prices.

32. For interrogatory 31 above, please explain the difference, if any, between the option price and the corresponding futures price, forward price, or comparable market price for the future period (the period being hedged) that is greater than 5 percent of the option price.

A. Tampa Electric did not use options to hedge natural gas prices.

33. For open hedging transactions since August 1, 2015, has TECO experienced any defaults by a counter-party? If yes, please identify the counter-party and explain.

A. No, Tampa Electric has not experienced any counterparty defaults for open hedging transactions since August 1, 2015.

34. Does TECO use firm gas storage for physically hedging the price of natural gas? Please explain your response.

A. No, Tampa Electric does not use its firm gas storage for physically hedging the price of natural gas. The company utilizes firm gas storage to provide operational flexibility and reliability for its natural gas supply.

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 Manager, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Sixth Set of Interrogatories, (Nos. 29-34) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 27th day of September, 2016.

Penelope Rusk

Sworn to and subscribed before me this 27th day of September, 2016.

Notary Public State of Florida
Tison C Vega
My Commission FF 955624
Expires 02/01/2020

My Commission expires _____

105

TECO's Response to Staff's Sixth Set of Interrogatories, Nos. 29 (Confidential DN 07882-16)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 105
PARTY: STAFF – (DIRECT)
DESCRIPTION: Penelope A. Rusk

106

TECO's Response to Staff's Seventh Set of Interrogatories, No. 35 (Redacted)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 106
PARTY: STAFF – (DIRECT)
DESCRIPTION: Penelope A. Rusk

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	))))	DOCKET NO. 160001-EI FILED: OCTOBER 5, 2016

REDACTED

TAMPA ELECTRIC COMPANY'S

ANSWERS TO SEVENTH SET OF INTERROGATORIES (NO. 35)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (No. 35) propounded and served on September 15, 2016 by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 160001-EI
INDEX TO STAFF'S SEVENTH SET OF INTERROGATORIES (NO. 35)

Number	Witness	Subject	Bates Stamped Page
35	Caldwell	For the purpose of this interrogatory, please refer to Tampa Electric's Response to Staff's 4th Set of Interrogatories (No. 17), dated August 29, 2016. Within the response, this follow up interrogatory pertains to information the Company provided in the Column labeled "2015," and specifically to the "Yearly Average" value (Row 13) and "Range identified in Risk Management Plan" information (Row 14) for 2015. a. Based on the Company's response, the "Yearly Average" value (Row 13 and Column for 2015) reported for 2015 was outside of the range for that year as stated in the "Range identified in Risk Management Plan" information (Row 14 and Column for 2015). Please explain the reason(s) for this result, including in your response any unique market conditions, or events that contributed to this result. b. Based on the most current actual and estimated information the Company has, what "Yearly Average" value (Row 13) is the Company projecting for 2016?	1

Brent Caldwell
Director, Fuel Planning and Services

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

35. For the purpose of this interrogatory, please refer to Tampa Electric's Response to Staff's 4th Set of Interrogatories (No. 17), dated August 29, 2016. Within the response, this follow up interrogatory pertains to information the Company provided in the Column labeled "2015," and specifically to the "Yearly Average" value (Row 13) and "Range identified in Risk Management Plan" information (Row 14) for 2015.

a. Based on the Company's response, the "Yearly Average" value (Row 13 and Column for 2015) reported for 2015 was outside of the range for that year as stated in the "Range identified in Risk Management Plan" information (Row 14 and Column for 2015). Please explain the reason(s) for this result, including in your response any unique market conditions, or events that contributed to this result.

b. Based on the most current actual and estimated information the Company has, what "Yearly Average" value (Row 13) is the Company projecting for 2016?

A. a. The reason the yearly average value reported for 2015 was outside the range is due to increased natural gas-fired generation compared to the projection. The mathematical result of higher than projected natural gas-fired generation is a lower than expected percentage of the total projected natural gas consumption being hedged. Had natural gas consumption matched the projected quantity, the percentage hedged would have been inside the range.

The factors that caused this greater than projected actual natural gas consumption included the following: coal unit outage, greater than projected load, and lower than projected natural gas prices. An unusual market factor occurred during this time period: Natural gas prices decreased to $2.00 per MMBtu or less at the Henry Hub for several months between October, 2015 and April, 2016. At this price, coal-fired generation was displaced with natural gas-fired combined cycle generation during off-peak periods. As such, the increase in actual compared to projected natural gas-fired generation reduced the effective percentage of natural gas consumption that was hedged.

REDACTED

b. Tampa Electric expects the 2016 annual average to be [redacted][1] The company projects a value near the low end of the range due to the low natural gas prices in the first part of 2016 which increased natural gas-fired generation compared to projected. (See the response to subpart (a) for more information about the low natural gas prices.)

[1] Actual data for January through August 2016 and estimated data for September through December 2016.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is Manager, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Seventh Set of Interrogatories, (No. 35) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 4th day of October, 2016.

Penelope Rusk

Sworn to and subscribed before me this 4th day of October, 2016.

Notary Public State of Florida
Tison C Vega
My Commission FF 955624
Expires 02/01/2020

My Commission expires _____

107

TECO's Response to Staff's Seventh Set of Interrogatories, No. 35 (Confidential DN 08025-16)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 107
PARTY: STAFF – (DIRECT)
DESCRIPTION: Penelope A. Rusk

108

TECO's Response to Staff's Eighth Set of Interrogatories, No. 36

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 108
PARTY: STAFF – (DIRECT)
DESCRIPTION: Penelope A. Rusk

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	))))	DOCKET NO. 160001-EI FILED: OCTOBER 13, 2016

TAMPA ELECTRIC COMPANY'S

ANSWERS TO EIGHTH SET OF INTERROGATORIES (NO. 36)

OF

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Interrogatories (No. 36) propounded and served on September 29, 2016 by the Florida Public Service Commission Staff.

TAMPA ELECTRIC COMPANY
DOCKET NO. 160001-EI
INDEX TO STAFF'S EIGHTH SET OF INTERROGATORIES (NO. 36)

Number	Witness	Subject	Bates Stamped Page
36	Rusk	For the purpose of this interrogatory and subparts, please refer to the following two documents: • Document 1, Page 23 of 25, of Exhibit PAR-2, exhibit attached to the Direct Testimony of Penelope A. Rusk, filed in Docket No. 160001-EI, on August 4, 2016 ("Schedule E7 for Actual / Estimated period of January-December, 2016"). • Document 2, Page 26 of 30, of Exhibit PAR-3, exhibit attached to the Direct Testimony of Penelope A. Rusk, filed in Docket No. 160001-EI, on September 1, 2016 ("Schedule E7 for Estimated period of January-December, 2017"). a. Referring to Column 4 in the Schedule E7 for Actual / Estimated period of January-December, 2016, TECO estimates that its Purchased Power will be 2,001,164 Megawatt Hours through December, 2016. Please explain how this quantity of Megawatt Hours compares to the quantity the Company's projected for 2016, explaining the variance. b. Referring to Column 9 in the Schedule E7 for Actual / Estimated period of January-December, 2016, TECO estimates that the Total For Fuel Adjustment will be $48,263,990 through December, 2016. Please explain how this amount compares to the amount the Company's projected for 2016, explaining the variance. c. Referring to Column 4 in the Schedule E7 for Actual / Estimated period of January-December, 2016, TECO estimates that its Purchased Power will be 2,001,164 Megawatt Hours through December, 2016. Referring to Column 4 in the Schedule E7 for Estimated period of January-December, 2017, TECO estimates that its Purchased Power will be 25,290 Megawatt Hours through December, 2017. Please explain the variance between the two amounts, including in your response	1

		the reasons the estimated 2017 amount is substantially lower than the actual/estimated 2016 amount. d. Referring to Column 9 in the Schedule E7 for Actual / Estimated period of January-December, 2016, TECO estimates that the Total For Fuel Adjustment will be $48,263,990 through December, 2016. Referring to Column 9 in the Schedule E7 for Estimated period of January-December, 2017, TECO estimates that the Total For Fuel Adjustment will be $1,172,410 through December, 2017. Please explain the variance between the two amounts, including in your response the reasons the estimated 2017 amount is substantially lower than the actual/estimated 2016 amount.	

Penelope Rusk
Manager, Rates

Tampa Electric Company
702 N. Franklin Street
Tampa, Florida 33602

36. For the purpose of this interrogatory and subparts, please refer to the following two documents:

- Document 1, Page 23 of 25, of Exhibit PAR-2, exhibit attached to the Direct Testimony of Penelope A. Rusk, filed in Docket No. 160001-EI, on August 4, 2016 ("Schedule E7 for Actual / Estimated period of January-December, 2016").
- Document 2, Page 26 of 30, of Exhibit PAR-3, exhibit attached to the Direct Testimony of Penelope A. Rusk, filed in Docket No. 160001-EI, on September 1, 2016 ("Schedule E7 for Estimated period of January-December, 2017").

a. Referring to Column 4 in the Schedule E7 for Actual / Estimated period of January-December, 2016, TECO estimates that its Purchased Power will be 2,001,164 Megawatt Hours through December, 2016. Please explain how this quantity of Megawatt Hours compares to the quantity the Company's projected for 2016, explaining the variance.

b. Referring to Column 9 in the Schedule E7 for Actual / Estimated period of January-December, 2016, TECO estimates that the Total For Fuel Adjustment will be $48,263,990 through December, 2016. Please explain how this amount compares to the amount the Company's projected for 2016, explaining the variance.

c. Referring to Column 4 in the Schedule E7 for Actual / Estimated period of January-December, 2016, TECO estimates that its Purchased Power will be 2,001,164 Megawatt Hours through December, 2016. Referring to Column 4 in the Schedule E7 for Estimated period of January-December, 2017, TECO estimates that its Purchased Power will be 25,290 Megawatt Hours through December, 2017. Please explain the variance between the two amounts, including in your response the reasons the estimated 2017 amount is substantially lower than the actual/estimated 2016 amount.

d. Referring to Column 9 in the Schedule E7 for Actual / Estimated period of January-December, 2016, TECO estimates that the Total For Fuel Adjustment will be $48,263,990 through December, 2016. Referring to Column 9 in the Schedule E7 for Estimated period of January-December, 2017, TECO estimates that the Total For Fuel Adjustment will be $1,172,410 through December, 2017. Please explain the variance between the two amounts, including in your response the reasons the

estimated 2017 amount is substantially lower than the actual/estimated 2016 amount.

A. a. Referring to Column 4 in Schedule E7 for the Actual / Estimated period of January-December 2016, the estimated MWh of 2,001,164 is greater than the original 2016 Schedule E7 for the Estimated period of January-December, 2016, Column 4, filed September 1, 2015, of 539,580 MWh, by 1,461,584 MWh. As stated in the testimony of witness Benjamin F. Smith, submitted in this docket on September 1, 2016, the company purchased more power than originally planned due to the economical results of its RFP. Some power was purchased due to Polk CT 2-5 not being available for dispatch at some times during 2016, due to the CTs' conversion to the Polk 2 Combined Cycle unit.

b. Referring to Column 9 in Schedule E7 for the Actual / Estimated period of January-December 2016, the estimated Total for Fuel Adjustment of $48,263,990 is greater than the original 2016 Schedule E7 for the Estimated period of January-December, 2016, Column 9, filed September 1, 2015, of $19,799,520, by $28,464,470. As stated in the testimony of witness Benjamin F. Smith, submitted in this docket on September 1, 2016, the company purchased more power than originally planned due to the economical results of its RFP. Some power was purchased due to Polk CT 2-5 not being available for dispatch at some times during 2016, due to the CTs' conversion to the Polk 2 Combined Cycle unit.

c. Referring to Column 4 in Schedule E7 for the Actual / Estimated period of January-December 2016, the estimated MWh of 2,001,164 is greater than the 2017 Schedule E7 for the Estimated period of January-December, 2017, Column 4, of 25,290 MWh, by 1,975,874 MWh. This is due to the expiration of the purchase agreements entered for economics and to provide substitute resources during the completion of the Polk 2 Combined Cycle project.[1] As previously mentioned, these purchase agreements are described in the direct testimony of Benjamin F. Smith.

d. Referring to Column 9 in Schedule E7 for the Actual / Estimated period of January-December 2016, the estimated Total for Fuel Adjustment of $48,263,990 is greater than the 2017 Schedule E7 for the Estimated

[1] Polk Unit 2 Combined Cycle is expected to begin commercial service in January 2017.

period of January-December, 2017, Column 9, of $1,172,410, by $47,091,580. This is due to the expiration of the purchase agreements entered for economics and to provide substitute resources during the completion of the Polk 2 Combined Cycle project.[2] As previously mentioned, these purchase agreements are described in the direct testimony of Benjamin F. Smith.

[2] Polk Unit 2 Combined Cycle is expected to begin commercial service in January 2017.

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 Manager, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Eighth Set of Interrogatories, (No. 36) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 12th day of October, 2016.

Penelope Rusk

Sworn to and subscribed before me this 12th day of October, 2016.

Notary Public State of Florida
Tison C Vega
My Commission FF 955624
Expires 02/01/2020

My Commission expires _____

109

Joint Motion For Approval of Settlement Agreement, filed on October 6, 2016 in Docket Nos. 160021-EI, 160061-EI, 160062-EI and 160088-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 109
PARTY: STAFF – (DIRECT)
DESCRIPTION: R.B. Deaton

FILED OCT 06, 2016
DOCUMENT NO. 08050-16
FPSC - COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company	Docket No. 160021-EI
In re: Petition for approval of 2016-2018 storm hardening plan, by Florida Power & Light Company	Docket No. 160061-EI
In re: 2016 depreciation and dismantlement study by Florida Power & Light Company	Docket No. 160062-EI
In re: Petition for limited proceeding to modify and continue incentive mechanism by Florida Power & Light Company	Docket No. 160088-EI Filed: October 6, 2016

JOINT MOTION FOR APPROVAL OF SETTLEMENT AGREEMENT

Florida Power & Light Company ("FPL"), the Office of Public Counsel ("OPC"), the South Florida Hospital and Healthcare Association ("SFHHA") and the Florida Retail Federation ("FRF") (collectively referred to as the "Signatories") jointly move the Florida Public Service Commission ("Commission") to review and approve on an expedited basis the attached Stipulation and Settlement as full and complete resolution of all matters pending in Docket Nos. 160021-EI, 160061-EI, 160062-EI and 160088-EI (the "Consolidated Proceedings") in accordance with Section 120.57(4), Florida Statutes, and to enter a final order reflecting such approval to effectuate implementation of the Stipulation and Settlement ("Settlement Agreement"). In support of this Joint Motion, the Signatories state:

1. The Signatories have been engaged in negotiations for the purpose of reaching a comprehensive stipulation and settlement of all issues in the Consolidated Proceedings, thereby avoiding the uncertainty associated with the outcome on the issues. These negotiations have culminated in the Settlement Agreement attached hereto as Exhibit A. The Signatories request that, following the Commission's review of this Joint Motion and the Settlement Agreement, the

Commission grant the Joint Motion and approve the Settlement Agreement in order to allow for orderly implementation thereof and provide certainty to the parties and their respective constituents and customers with respect to the outcome of the Consolidated Proceedings.

2. The Settlement Agreement provides, among other things:

a. The Agreement would become effective on January 1, 2017 and continue until FPL's base rates are next reset in a general base rate proceeding (the "Term"), with the minimum term of the Agreement being four years through December 31, 2020 (the "Minimum Term"). Except as expressly provided in the Settlement Agreement, FPL could not seek another base rate increase during the term of the Settlement Agreement. FPL retains the right, however, to place new rates in effect following the end of the Minimum Term, subject to refund, upon a request for a base rate change pursuant to Section 366.06, Florida Statutes.

b. Base rate adjustments as follows:

i. A $400 million increase, effective January 1, 2017. This is a $426 million reduction from FPL's request.

ii. A $211 million increase, effective January 1, 2018. This is a $59 million reduction from FPL's request.

iii. A $200 million base rate adjustment upon the commercial operation date for the Okeechobee Clean Energy Center, projected to be June 2019. This is a $9 million reduction from FPL's request.

iv. Authority to implement Solar Base Rate Adjustments ("SoBRA") upon the commercial operation date of solar generation projects that FPL will undertake to construct during the Minimum Term or within one year

following expiration of the Minimum Term. Such solar projects will be subject to Commission approval as described in the Settlement Agreement, and, except as set forth therein, will not exceed 300 MW per year. For each SoBRA, FPL's base rates will be increased by the annualized base revenue requirement for the first 12 months of operation.

c. FPL's return on common equity ("ROE") would be 10.55% for purposes of setting rates. FPL's authorized ROE range for the Term is 9.60% - 11.60%.

d. The revenue requirement associated with West County Energy Center Unit 3 currently collected through the Capacity Cost Recovery Clause will be moved to base rates on a revenue neutral basis.

e. Pursuant to the depreciation parameters set forth in the Settlement Agreement, FPL's 2017 depreciation expense is estimated to be $125.8 million lower than was reflected in FPL's Second Notice of Identified Adjustments (Hearing Exhibit 331, Attachment 2), with a theoretical reserve surplus estimated to be $1,070.2 million. FPL would be given continued flexibility during the Term of the Settlement Agreement to amortize up to $1,000 million of the theoretical reserve surplus, with the obligation to use that flexibility to endeavor to maintain FPL's earned ROE within its authorized range. FPL would also be given the flexibility to amortize any remaining portion of the reserve amount as of December 31, 2016 that the Commission authorized as part of the 2012 Settlement Agreement in Order No. PSC-13-0023-S-EI (adjusted for the Cedar Bay Settlement in Order No. PSC-15-0401-AS-EI).

f. FPL will use a 10-year amortization period for the capital recovery schedules set forth on Hearing Exhibit 109, instead of FPL's proposed four-year amortization period.

g. The storm cost recovery mechanism provided in the 2010 and 2012 settlement agreements would remain in effect.

h. FPL is authorized to continue the incentive mechanism approved in Order PSC-13-0023-S-EI, subject to two modifications: (i) the initial threshold for sharing gains is $40 million to $100 million, and (ii) FPL will net economy sales and purchases in order to determine the impact of variable power plant O&M. If FPL executes more economy sales than economy purchases, it will recover the net amount of variable power plant O&M incurred in a given year. If economy purchases are greater than economy sales, FPL's customers will receive a credit for the net variable power plant O&M that has been saved in that year. The per-MWh variable power plant O&M rate used to calculate these costs shall be $0.65/MWh as described in the rebuttal testimony of FPL witness Sam Forrest.

i. FPL is authorized to transfer to its FERC-regulated affiliate, Florida Southeast Connection ("FSC") the Martin-Riviera ("MR-RV") Lateral natural gas pipeline, all related equipment, working capital and operations, upon a showing that such transfer will result in customer savings on a cumulative present value revenue requirements basis. FPL must file a petition to confirm the cost-effectiveness of the transaction to customers and to request approval to implement a simultaneous change to lower base rates and adjust fuel rates to reflect the projected transportation charges.

j. FPL agrees to terminate 100% of its natural gas financial hedging prospectively during the Minimum Term (i.e., commencing with FPL's 2017 Risk Management Plan). FPL will not be precluded from filing a petition and proposed risk management plan with the Commission to address natural gas hedging following expiration of the Minimum Term.

3. Each of the Signatories agrees that it has entered into the Settlement Agreement voluntarily, that it fairly and reasonably balances the various positions of the parties on issues in these proceedings, and that it serves the best interests of the customers they represent and the public interest in general. The Signatories believe that the Settlement Agreement is reasonable and in the public interest for several reasons, including the following:

a. The Settlement Agreement would provide for a reasonable base rate increase in consideration of FPL's overall request and recent increases for other electric utilities through litigated and settled outcomes.

b. As a result of this settlement, residential and business customers will see lower increases in their bills than they would have experienced under the original proposed increase.

c. The Settlement Agreement provides FPL customers with stability and predictability with respect to their electricity rates, while allowing FPL to maintain the financial strength to make investments it believes are necessary to provide customers with safe and reliable power.

d. The Settlement Agreement also serves the public interest by increasing the amount of emissions-free solar power and energy that will be available to serve all of FPL's customers on a cost-effective basis.

For these reasons, approving the Settlement Agreement is fully consistent with the Commission's long-standing policy of encouraging the settlement of contested proceedings in a manner that benefits the customers of utilities subject to the Commission's regulatory jurisdiction.

4. The Signatories request that the Commission rule on this Joint Motion To Approve Settlement as promptly as possible but in no event later than November 30, 2016 so that its terms can be implemented by January 1, 2017.

5. All Signatories agree with and support this Joint Motion for approval of the Settlement Agreement. Due to the conditions surrounding Hurricane Matthew, the Signatories were unable to reach other parties to this proceeding to determine their positions at the time of this filing. The Signatories will endeavor to do so as soon as practicable after Hurricane Matthew, and will file an updated certificate of conferral with the Commission.

160001 Hearing Exhibits 00233

WHEREFORE, FPL, OPC, SFHHA and FRF respectfully request that the Commission approve the Stipulation and Settlement attached hereto as Exhibit A.

Respectfully submitted,

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John T. Butler, Assistant General Counsel-Regulatory
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By: *s/ Robert Scheffel Wright*

CERTIFICATE OF SERVICE
160021-EI, 160061-EI, 160062-EI and 160088-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail this 6th day of October 2016 to the following parties:

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By: *s/ R. Wade Litchfield*
R. Wade Litchfield

EXHIBIT A

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company	Docket No. 160021-EI
In re: Petition for approval of 2016-2018 storm hardening plan, by Florida Power & Light Company	Docket No. 160061-EI
In re: 2016 depreciation and dismantlement study by Florida Power & Light Company	Docket No. 160062-EI
In re: Petition for limited proceeding to modify and continue incentive mechanism by Florida Power & Light Company	Docket No. 160088-EI Filed: October 6, 2016

STIPULATION AND SETTLEMENT

WHEREAS, Florida Power & Light Company ("FPL" or the "Company"), Citizens through the Office of Public Counsel ("OPC"), the South Florida Hospital and Healthcare Association ("SFHHA") and the Florida Retail Federation ("FRF") have signed this Stipulation and Settlement (the "Agreement"; unless the context clearly requires otherwise, the term "Party" or "Parties" means a signatory to this Agreement); and

WHEREAS, on January 14, 2013, the Florida Public Service Commission ("FPSC" or "Commission") entered Order No. PSC-13-0023-S-EI approving a stipulation and settlement of FPL's rate case in Docket No. 120015-EI, which continues in effect through the last billing cycle in December 2016 (the "2012 Rate Case Settlement"); and

WHEREAS, on March 15, 2016, FPL petitioned the Commission for (i) an increase in rates and charges sufficient to generate additional total annual revenues of $866 million to be effective January 1, 2017; (ii) a subsequent year revenue increase of $262 million to be effective January 1, 2018; (iii) a $209 million limited-scope adjustment for the Okeechobee Clean Energy Center ("the Okeechobee Unit"), to be effective on its commercial in-service date, currently

scheduled for June 1, 2019 (the "2019 Okeechobee LSA"), and for other related relief in Docket 160021-EI (the "2016 Rate Petition"); and

WHEREAS, through Notices of Identified Adjustments, FPL updated its request to $826 million in 2017, $270 million in 2018 and $209 million for the 2019 Okeechobee LSA.

WHEREAS, on March 15, 2016, FPL petitioned for approval of its 2016-2018 storm hardening plan in Docket 160061-EI; and

WHEREAS, on March 15, 2016, FPL filed its dismantlement and depreciation studies in Docket No. 160062-EI; and

WHEREAS, on April 15, 2016, FPL petitioned for approval of modification to and continuation of its incentive mechanism in Docket 160088-EI; and

WHEREAS, on May 4, 2016, the Commission consolidated Dockets 160021-EI, 160061-EI, 160062-EI and 160088-EI (collectively, "the Consolidated Proceedings"); and

WHEREAS, the Parties filed voluminous prepared testimony with accompanying exhibits and conducted extensive discovery in the Consolidated Proceedings; and

WHEREAS, the Parties participated in a nine-day technical hearing involving live testimony and cross-examination of 17 FPL direct witnesses, 16 intervenor witnesses, 2 Staff witnesses and 17 FPL rebuttal witnesses; and

WHEREAS, the Parties to this Agreement have undertaken to resolve the issues raised in the Consolidated Proceedings so as to maintain a degree of stability and predictability with respect to FPL's base rates and charges; and

WHEREAS, the Parties have entered into this Agreement in compromise of positions taken in accord with their rights and interests under Chapters 350, 366 and 120, Florida Statutes, as applicable, and as a part of the negotiated exchange of consideration among the parties to this

Agreement each has agreed to concessions to the others with the expectation that all provisions of the Agreement will be enforced by the Commission as to all matters addressed herein with respect to all Parties regardless of whether a court ultimately determines such matters to reflect Commission policy, upon acceptance of the Agreement as provided herein and upon approval in the public interest;

NOW THEREFORE, in consideration of the foregoing and the covenants contained herein, the Parties hereby stipulate and agree:

1. This Agreement will become effective on January 1, 2017 (the "Implementation Date") and continue until FPL's base rates are next reset in a general base rate proceeding (the "Term"); provided, however, that FPL may place interim rates into effect subject to refund pursuant to Paragraph 11(a) of this Agreement. The minimum term of this Agreement shall be four years, from the Implementation Date through December 31, 2020 (the "Minimum Term").

2. Except as set forth in this Agreement, the Parties agree that adjustments to rate base, net operating income and cost of capital set forth in FPL's Minimum Filing Requirements ("MFR") Schedules B-2, C-1, C-3 and D1a, as revised by the filed notices of identified adjustments, shall be deemed approved for accounting and regulatory reporting purposes and the accounting for those adjustments will not be challenged during the Term for purposes of FPL's Earnings Surveillance Reports or clause filings.

3. FPL's authorized rate of return on common equity ("ROE") shall be a range of 9.6% to 11.6%, and shall be used for all purposes. All rates, including those established in clause proceedings during the Term, shall be set using a 10.55% ROE.

160001 Hearing Exhibits 00240

4. (a) Effective on January 1, 2017, FPL shall be authorized to increase its base rates and service charges by an amount that is intended to generate an additional $400 million of annual revenues, based on the projected 2017 test year billing determinants set forth in Schedules E-13c and E-13d of FPL's 2017 MFRs filed with the 2016 Rate Petition, and in the respective amounts and manner shown on Exhibit A, attached hereto.

(b) Effective January 1, 2018, FPL shall be authorized to increase its base rates by an amount that is intended to generate an additional $211 million over the Company's then current base rates, based on the projected 2018 test year billing determinants set forth in Schedules E-13c and E-13d of FPL's 2018 MFRs filed with the 2016 Rate Petition, and in the respective amounts and manner shown on Exhibit A, attached hereto.

(c) Attached hereto as Exhibit B are tariff sheets for new base rates and service charges that reflect the terms of this Agreement and implement the rate increase described in Paragraph (4)(a) above, which tariff sheets shall become effective on January 1, 2017.

(d) Attached hereto as Exhibit C are tariff sheets for new base rates and service charges that reflect the terms of this Agreement and implement the additional rate increase described in Paragraph (4)(b) above, which tariff sheets shall become effective on January 1, 2018.

(e) As part of the negotiated exchange of consideration among the parties to this Agreement, (i) the energy and demand charges for business and commercial rates and the utility-controlled demand rates are adjusted as shown on Exhibits B and C, and (ii) the level of utility-controlled demand credits for customers receiving service pursuant to

160001 Hearing Exhibits 00241

FPL's Commercial/ Industrial Load Control ("CILC") tariff and the Commercial/Industrial Demand Reduction ("CDR") rider are the same as those currently in effect, which are greater than the proposed credits reflected in FPL's MFRs as originally filed on March 15, 2016. FPL shall be entitled to recover the CILC and CDR credits through the energy conservation cost recovery ("ECCR") clause. It is agreed that the appropriate level of credits is an issue in Demand-Side Management ("DSM") proceedings. The Parties agree that no changes in these credits shall be implemented any earlier than the effective date of new FPL base rates implemented pursuant to a general base rate proceeding, and that such new CILC and CDR credits shall only be implemented prospectively from such effective date. No CILC or CDR customer shall be subject to any charge or debit against such customer's bill for electric service provided during the Term based on the difference between the credits approved by this Agreement and any new credits that may be approved pursuant to future DSM proceedings. At such time as FPL's base rates are reset in a general base rate proceeding, the CILC and CDR credits shall be reset to the level established in FPL's then most recent DSM proceeding, subject to any applicable refund occasioned by a timely exercised right of reconsideration or appellate review of any order associated with the DSM proceeding. No party to this Agreement may object to FPL's recovery of any such refund through the ECCR Clause

(f) The rates set forth in Exhibits B and C are calculated based on a cost of service study that applies (i) the 12 CP and 1/13 methodology for Production Plant, (ii) 12 CP for Transmission Plant and (iii) a negotiated methodology for allocating Distribution Plant, limited by the Commission's traditional gradualism test found in Order No. PSC-09-0283-FOF-EI, pp. 86-87. Under the rates set forth in Exhibits B and C, no rate or

160001 Hearing Exhibits 00242

revenue class receives (nor shall receive) an increase greater than 1.5 times the system average percentage increase in total and no class receives (nor shall receive) a decrease in rates.

(g) The following proposed tariff changes as filed shall be implemented:

(i) Implementation of the new meter tampering service charge;

(ii) Implementation of metered rates for all new customer-owned street lighting (SL-1) and traffic signal (SL-2) accounts;

(iii) Elimination of the re-lamping option for customer-owned lighting;

(iv) Three changes to the terms of service for the Outdoor Lighting (OL-1) tariff; and

(v) Identified changes to the requirements for surety bonds.

(h) Base rates and credits applied to customer bills in accordance with this Paragraph 4 shall not be changed during the Minimum Term except as otherwise permitted in this Agreement.

5. Nothing in this Agreement shall preclude FPL from requesting the Commission to approve the recovery of costs that are recoverable through base rates under the nuclear cost recovery statute, Section 366.93, Florida Statutes, and Commission Rule 26-6.0423, F.A.C. Nothing in this Agreement prohibits parties from participating without limitation in nuclear cost recovery proceedings and proceedings related thereto and opposing FPL's requests.

160001 Hearing Exhibits 00243

6. (a) Nothing in this Agreement shall preclude FPL from petitioning the Commission to seek recovery of costs associated with any storms without the application of any form of earnings test or measure and irrespective of previous or current base rate earnings or the remaining unamortized Reserve Amount as defined in Paragraph 12. Consistent with the rate design method set forth in Order No. PSC-06-0464-FOF-EI, the Parties agree that recovery of storm costs from customers will begin, on an interim basis, sixty days following the filing of a cost recovery petition and tariff with the Commission and will be based on a 12-month recovery period if the storm costs do not exceed $4.00/1,000 kWh on monthly residential customer bills. In the event the storm costs exceed that level, any additional costs in excess of $4.00/1,000 kWh may be recovered in a subsequent year or years as determined by the Commission. All storm related costs subject to interim recovery under this Paragraph 6 shall be calculated and disposed of pursuant to Commission Rule 25-6.0143, F.A.C., and will be limited to costs resulting from a tropical system named by the National Hurricane Center or its successor, to the estimate of incremental costs above the level of storm reserve prior to the storm and to the replenishment of the storm reserve to the level in effect as of August 31, 2016. The Parties to this Agreement are not precluded from participating in any such proceedings and opposing the amount of FPL's claimed costs but not the mechanism agreed to herein, provided that it is applied in accordance with this Agreement.

(b) The Parties agree that the $4.00/1,000 kWh cap in this Paragraph 6 will apply in aggregate for a calendar year for the purpose of the interim recovery set forth in 6(a) above; provided, however, that FPL may petition the Commission to allow FPL to increase the initial 12 month recovery beyond $4.00/1,000 kWh in the event FPL incurs

in excess of $800 million of storm recovery costs that qualify for recovery in a given calendar year, inclusive of the amount needed to replenish the storm reserve to the level that existed as of August 31, 2016. All Parties reserve their right to oppose such a petition.

(c) Any proceeding to recover costs associated with any storm shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings or the remaining unamortized Reserve Amount as defined in Paragraph 12.

7. Nothing shall preclude the Company from requesting Commission approval for recovery of costs (a) that are of a type which traditionally, historically and ordinarily would be, have been, or are presently recovered through cost recovery clauses or surcharges, or (b) that are incremental costs not currently recovered in base rates which the Legislature or Commission determines are clause recoverable subsequent to the approval of this Agreement. It is the intent of the Parties in this Paragraph 7 that FPL not be allowed to recover through cost recovery clauses increases in the magnitude of costs of types or categories (including but not limited to, for example, investment in and maintenance of transmission assets) that have been, and traditionally, historically, and ordinarily would be, recovered through base rates. It is further the intent of the Parties to recognize that an authorized governmental entity may impose requirements on FPL involving new or atypical kinds of costs (including but not limited to, for example, requirements related to cyber security), and concurrently or in connection with the imposition of such

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requirements, the Legislature and/or Commission may authorize FPL to recover those related costs through a cost recovery clause.

8. The revenue requirement associated with West County Energy Center Unit 3 ("WCEC 3") currently collected through the Capacity Cost Recovery ("CCR") Clause will be moved to base rates on a revenue neutral basis and will not be considered an increase in base rates pursuant to Paragraph 4. FPL is authorized to recover through base rates the revenue requirements associated with WCEC 3, not limited to the unit's fuel savings. FPL's 2017 CCR Clause factor will reflect the elimination of FPL's collection of the WCEC 3 revenue requirement through the CCR Clause.

9. (a) FPL projects that its Okeechobee Unit will enter commercial service in June 2019. Effective as of the commercial in-service date of the Okeechobee Unit, FPL is authorized to increase its base rates by an amount that is intended to generate an additional $200 million for the costs associated with the Okeechobee Unit's first 12 months of operation (the "Annualized Base Revenue Requirement") over the 12 months beginning with the Okeechobee Unit's commercial in-service date. Such base rate increases shall be calculated based on FPL's then-most-current projections of sales (billing determinants) as reflected in its then-most-current CCR Clause filings with the Commission, including, to the extent necessary, projections of such billing determinants into 2020 so as to cover the same 12 months as the first 12 months of the Okeechobee Unit's operation. This base rate adjustment will be referred to as the Okeechobee Limited Scope Adjustment ("Okeechobee LSA").

(b) FPL is authorized to reflect the Okeechobee LSA on FPL's customer bills by adjusting base charges and non-clause recoverable credits and commercial/industrial

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demand reduction rider credits by an equal percentage. The calculation of the percentage change in rates is based on the ratio of the jurisdictional Annualized Base Revenue Requirement and the forecasted retail base revenues from the sales of electricity during the first twelve months of operation. FPL will begin applying the incremental base rate charges and base credits for the Okeechobee LSA to meter readings made on and after the commercial in-service date of the Okeechobee Unit. Fuel factors will be implemented to incorporate fuel savings contemporaneously with the Okeechobee LSA base rate increase.

(c) The Okeechobee LSA will be calculated using a 10.55% ROE and the capital structure reflected in the 2016 Rate Petition and MFRs as adjusted in accordance with the filed Notice of Identified Adjustments. FPL will calculate the 2019 Okeechobee LSA rates and submit them to the Commission for approval in the CCR Clause projection filing for 2019.

(d) In the event that the actual capital expenditures are less than the projected costs set forth in Order No. PSC-16-0032-FOF-EI, which were used to develop the initial Okeechobee LSA factor, the lower figure shall be the basis for the full revenue requirements and a one-time credit will be made through the CCR Clause. In order to determine the amount of this credit, a revised Okeechobee LSA Factor will be computed using the same data and methodology incorporated in the initial Okeechobee LSA factor, with the exception that the actual capital expenditures will be used in lieu of the capital expenditures on which the Annualized Base Revenue Requirement was based. Thereafter, base rates will be adjusted to reflect the revised Okeechobee LSA factor. The difference between the cumulative base revenues since the implementation of the initial

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Okeechobee LSA factor and the cumulative base revenues that would have resulted if the revised Okeechobee LSA factor had been in-place during the same time period will be credited to customers through the CCR Clause with interest at the 30-day commercial paper rate as specified in Rule 25-6.109, F.A.C.

(e) In the event that actual capital costs for the Okeechobee Unit are higher than the projection on which the Annualized Base Revenue Requirement was based, pursuant to the costs set forth in Order No. PSC-16-0032-FOF-EI, FPL at its option may initiate a limited proceeding pursuant Section 366.076, Florida Statutes, limited to the issue of whether FPL has met the requirements of Rule 25-22.082(15), F.A.C. If the Commission finds that FPL has met the requirements of Rule 25-22.082(15), then FPL shall be authorized to increase the Okeechobee LSA by the corresponding incremental revenue requirement due to such additional capital costs. However, FPL's election not to seek such an increase in the Okeechobee LSA shall not preclude FPL from booking any incremental costs for surveillance reporting and all regulatory purposes subject only to a finding of imprudence or disallowance by the Commission. Nothing in this Agreement shall preclude any party from participating in such limited proceeding consistent with the full rights of an intervenor.

(f) Depreciation revenue requirements for the Okeechobee LSA will be revised to reflect the final depreciation rates for the Port Everglades New Generation Clean Energy Center as reflected on Exhibit D herein.

(g) Upon expiration or termination of this Agreement, FPL's base rate levels and credits, including the effects of the Okeechobee LSA as implemented in this Agreement (i.e., uniform percent increase for all rate classes applied to base revenues), shall continue

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in effect until next reset in a general base rate proceeding except as otherwise noted in this Agreement.

10. (a) FPL projects that for purposes of the cost recovery set forth in this Paragraph, it will undertake construction of approximately 300 MW per calendar year of solar generation reasonably projected to go into service during the Minimum Term or within one year following expiration of the Minimum Term. For each solar project that is approved by the Commission for cost recovery pursuant to the process described in this Paragraph, FPL's base rates will be increased by the incremental annualized base revenue requirement (as defined in Paragraph 10(e)) for the first 12 months of operation (the "Annualized Base Revenue Requirement"), but in no event before the facility is in service. Each such base rate adjustment will be referred to as a Solar Base Rate Adjustment ("SoBRA"), and shall be authorized for solar projects for which FPL files for Commission approval pursuant to this Paragraph during the Minimum Term. The Commission's approval may occur before or after expiration of the Minimum Term. The projects constructed pursuant to this Paragraph must be reasonably scheduled to be placed into service no later than one year following the expiration of the Minimum Term. During the Term of this Agreement, the cost of the components, engineering and construction for any solar project constructed by FPL pursuant to this Paragraph shall be reasonable and in no event shall the total cost of such project exceed $1,750 per kilowatt alternating current ("kWac").

(b) For solar generation projects subject to the Florida Electrical Power Plant Siting Act (i.e., 75 MW or greater), FPL will file a petition for need determination pursuant to Chapter 25-22, F.A.C. If approved pursuant to the procedures described in this

Paragraph and Section 403.519, Fla. Stat., FPL will calculate and submit for Commission confirmation that amount of the SoBRA for each such solar project using the CCR Clause projection filing for the year that solar project will go into service.

(c) Solar generation projects not subject to the Florida Electrical Power Plant Siting Act (i.e., fewer than 75 MW) also will be subject to approval by the Commission as follows: (i) FPL will file a request for approval of the solar generation project at the time of its final true-up filing in the Fuel and Purchased Power Cost Recovery Clause docket) ("Fuel Docket"); (ii) All Fuel Docket deadlines and schedules shall apply; (iii) the issues for determination are limited to the cost effectiveness of each such project (i.e., will the project lower the projected system cumulative present value revenue requirement "CPVRR" as compared to such CPVRR without the solar project) and the amount of revenue requirements and appropriate percentage increase in base rates needed to collect the estimated revenue requirements; and (iv) approval of the solar generation project will be an issue to be resolved at the regularly scheduled Fuel Docket hearing; provided, however, that the Commission on its own initiative or upon good cause shown by an intervenor (which may include any Party to this Agreement or any other entity satisfying the standing requirements of Florida law) may set FPL's request for approval of the solar generation project for a separate hearing to be held in the Fuel Docket before the end of that calendar year. If approved, FPL will calculate and submit for Commission confirmation the amount of the SoBRA for each such solar project using the CCR Clause projection filing for the year that solar project will go into service. For a solar project that is scheduled to go into service in 2017, FPL shall not implement a base rate adjustment until such project is approved by the Commission pursuant to this Paragraph

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10. For each solar project approved pursuant to this Agreement, the base rate increase shall be based upon FPL's billing determinants for the first 12 months following such project's commercial in-service date, where such billing determinants are those used in FPL's then-most-current CCR Clause filings with the Commission, including, to the extent necessary, projections of such billing determinants into a subsequent calendar year so as to cover the same 12 months as the first 12 months of each such solar project's operation.

(d) FPL may not receive approval in any one year for incremental SoBRA recovery of more than 300 MW of solar projects for a calendar year; provided, however, to the extent that FPL receives approval for SoBRA recovery of less than 300 MW in a year, the surplus capacity can be carried over to the following years through the period identified in the first sentence of Paragraph 10(a). For example, if FPL receives approval in 2017 for SoBRA recovery of 200 MW of solar capacity, it would be entitled to increase its request in the subsequent year(s) for SoBRA of an additional 100 MW.

(e) Each SoBRA is to be reflected on FPL's customer bills by increasing base charges and base non-clause recoverable credits and commercial/industrial demand reduction rider credits by an equal percentage contemporaneously. The calculation of the percentage change in rates is based on the ratio of the jurisdictional Annualized Base Revenue Requirement and the forecasted retail base revenues from the sales of electricity during the first twelve months of operation. FPL will begin applying the incremental base rate charges and base credits for each SoBRA to meter readings made on and after the commercial in-service date of that solar generation site.

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(f) Each SoBRA will be calculated using a 10.55% ROE and the appropriate incremental capital structure consistent with the approach authorized for the Okeechobee LSA and adjusted to reflect the inclusion of investment tax credits on a normalized basis. FPL will calculate and submit for Commission approval the amount of the SoBRA for each solar generation project using the CCR Clause projection filing for the year that solar project is expected to go into service.

(g) In the event that the actual capital expenditures are less than the projected costs used to develop the initial SoBRA factor, the lower figure shall be the basis for the full revenue requirements and a one-time credit will be made through the CCR Clause. In order to determine the amount of this credit, a revised SoBRA Factor will be computed using the same data and methodology incorporated in the initial SoBRA factor, with the exception that the actual capital expenditures will be used in lieu of the capital expenditures on which the Annualized Base Revenue Requirement was based. On a going forward basis, base rates will be adjusted to reflect the revised SoBRA factor. The difference between the cumulative base revenues since the implementation of the initial SoBRA factor and the cumulative base revenues that would have resulted if the revised SoBRA factor had been in-place during the same time period will be credited to customers through the CCR Clause with interest at the 30-day commercial paper rate as specified in Rule 25-6.109, F.A.C.

(h) Subject to the maximum cost of $1,750 per kWac set forth in the subparagraph 10(a), in the event that actual capital costs for a solar generation project are higher than the projection on which the Annualized Base Revenue Requirement was based, FPL at its option may initiate a limited proceeding per Section 366.076, Florida Statutes, limited to

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the issue of whether FPL has met the requirements of Rule 25-22.082(15), F.A.C. Nothing in this Agreement shall prohibit a Party from participating in any such limited proceeding for the purpose of challenging whether FPL has met the requirements of Rule 25-22.082(15) or otherwise acted in accordance with this Agreement. If the Commission finds that FPL has met the requirements of Rule 25-22.082(15), then FPL shall increase the SoBRA by the corresponding incremental revenue requirement due to such additional capital costs, provided, consistent with subparagraph 10(a) above, FPL is prohibited from recovering through the SoBRA mechanism any costs greater than $1,750 per kWac under any circumstances. However, FPL's election not to seek such an increase in the SoBRA shall not preclude FPL from booking any incremental costs for surveillance reporting and all regulatory purposes subject only to a finding of imprudence or disallowance by the Commission. Nothing in this Agreement shall preclude any Party to this Agreement or any other lawful party from participating, consistent with the full rights of an intervenor, in any such limited proceeding.

(i) FPL's base rate and credit levels applied to customer bills, including the effects of the SoBRAs as implemented pursuant to this Agreement (i.e., uniform percent increase for all rate classes applied to base revenues), shall continue in effect until next reset by the Commission in a general base rate proceeding.

11. (a) Notwithstanding Paragraph 4 above, if FPL's earned return on common equity falls below the bottom of its authorized range during the Minimum Term on an FPL monthly earnings surveillance report stated on an FPSC actual, adjusted basis, FPL may petition the FPSC to amend its base rates, either as a general rate proceeding under Sections 366.06 and 366.07, Florida Statutes, or as a limited proceeding under Section

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366.076, Florida Statutes. Throughout this Agreement, "FPSC actual, adjusted basis" and "actual adjusted earned return" shall mean results reflecting all adjustments to FPL's books required by the Commission by rule or order, but excluding pro forma, weather-related adjustments. If FPL files a petition to initiate a general rate proceeding pursuant to this provision, FPL may request an interim rate increase pursuant to the provisions of Section 366.071, Florida Statutes. Nothing in this Agreement shall preclude any Party from participating in any proceeding initiated by FPL to increase base rates pursuant to this Paragraph consistent with the full rights of an intervenor.

(b) Notwithstanding Paragraph 4 above, if, during the Minimum Term of this Agreement, FPL's earned return on common equity exceeds the top of its authorized ROE range reported in an FPL monthly earnings surveillance report stated on an FPSC actual, adjusted basis, any Party other than FPL shall be entitled to petition the Commission for a review of FPL's base rates. In any case initiated pursuant to this Paragraph, all parties will have full rights conferred by law.

(c) Notwithstanding Paragraph 4 above, this Agreement shall terminate upon the effective date of any final order issued in any such proceeding pursuant to this Paragraph 11 that changes FPL's base rates.

(d) This Paragraph 11 shall not (i) be construed to bar or limit FPL to any recovery of costs otherwise contemplated by this Agreement pursuant to Paragraphs 5 through 10 nor, in any proceeding initiated after a base rate proceeding filed pursuant to this Paragraph, shall any Party be prohibited from taking any position or asserting the application of law or any right or defense in litigation related to FPL's efforts to recover such costs; (ii) apply to any request to change FPL's base rates that would become

effective after this Agreement terminates; or (iii) limit any Party's rights in proceedings concerning changes to base rates that would become effective subsequent to the termination of this Agreement to argue that FPL's authorized ROE range or any other element used in deriving its revenue requirements or rates should differ from the range set forth in this Agreement.

12. (a) In Order No. PSC-13-0023-S-EI, the Commission authorized FPL to amortize the total depreciation reserve surplus remaining at the end of 2012, plus a portion of FPL's fossil dismantlement reserve with the amounts to be amortized in each year from 2013 through 2016 left to FPL's discretion but not exceed a total of $400 million. That amount was later reduced to $370 million pursuant to the Cedar Bay settlement, Order No. PSC-15-0401-AS-EI. The 2016 Rate Petition and accompanying MFRs projected that FPL would have amortized the entire amount remaining at the end of 2016. The Parties acknowledge that the actual remaining amount may differ from the projection.

(b) The Parties agree that FPL is authorized to apply the depreciation parameters and resulting rates set forth in Exhibit D attached hereto, and acknowledge that application of those rates results in a $125.8 million reduction in 2017 test year depreciation expense (compared to application of the depreciation rates shown in Exhibit 331, Attachment 2) and a theoretical depreciation reserve surplus estimated to be $1,070.2 million at January 1, 2017. The Parties further agree that FPL will use a 10-year amortization period for the capital recovery schedules set forth on Exhibit 109, in lieu of FPL's proposed four-year amortization period.

(c) Notwithstanding the 2012 Rate Case Settlement, the Parties agree that until FPL's base rates are next reset in a general base rate proceeding, FPL may amortize any reserve

amount described in Paragraph 12(a) remaining at the end of 2016 and up to $1,000 million of the theoretical depreciation reserve surplus effected by the depreciation rates set forth in Exhibit D (together, the "Reserve Amount"), with the amounts to be amortized in each year of the Term left to FPL's discretion subject to the following conditions: (i) the amount that FPL may amortize during the Term shall not be less than the actual amount of depreciation reserve surplus remaining at the end of 2016; (ii) for any surveillance reports submitted by FPL during the Minimum Term on which its ROE (measured on an FPSC actual, adjusted basis) would otherwise fall below 9.6%, FPL must amortize at least the amount of the available Reserve Amount necessary to maintain in each such 12-month period an ROE of at least 9.6% (measured on an FPSC actual, adjusted basis); and (iii) FPL may not amortize the Reserve Amount in an amount that results in FPL achieving an ROE greater than 11.6% (measured on an FPSC actual, adjusted basis) in any such 12-month period as measured by surveillance reports submitted by FPL. FPL shall not satisfy the requirement of Paragraph 11 that its actual adjusted earned return on equity must fall below 9.6% on a monthly surveillance report before it may initiate a petition to increase base rates during the Minimum Term unless FPL first uses any of the Reserve Amount that remains available for the purpose of increasing its earned ROE to at least 9.6% for the period in question. FPL shall file an attachment to its monthly earnings surveillance report for December 2016 that shows the final amount of the 2012 "rollover" surplus that remained at the end of 2016. Thereafter, FPL shall file an attachment to its monthly surveillance report for December of each year during the Term that shows the amount of amortization credit or debit to the Reserve Amount on a monthly basis and year-end total basis for that calendar year. FPL

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may not amortize any portion of the Reserve Amount past December 31, 2020 unless it provides notice to the Parties by no later than March 31, 2020 that it does not intend to seek a general base rate increase to be effective any earlier than January 1, 2022.Any amortization of the Reserve Amount after December 31, 2020 shall be in accord with this Paragraph.

13. The level of FPL's annual dismantlement accrual shall be as set forth in Hearing Exhibit 343.

14. The Parties agree that the provisions of Rules 25-6.0436 and 25-6.04364, F.A.C., pursuant to which depreciation and dismantlement studies are generally filed at least every four years will not apply to FPL until FPL files its next petition to change base rates. The depreciation rates and dismantlement accrual rates in effect as of the Implementation Date shall remain in effect until FPL's base rates are next reset in a general base rate proceeding. At such time as FPL shall next file a general base rate proceeding, it shall simultaneously file new depreciation and dismantlement studies and propose to reset depreciation rates and dismantlement accrual rates in accordance with the results of those studies. The Parties agree to support consolidation of proceedings to reset FPL's base rates, depreciation rates and dismantlement accrual rates.

15. In Order PSC-130023-S-EI, the Commission authorized FPL to implement a Pilot Incentive Mechanism designed to create additional value for customers by FPL engaging in wholesale power purchases and sales, as well as all forms of asset optimization. The Parties agree that FPL is authorized to continue the Incentive Mechanism through the Term subject to the following modifications:

(a) On an annual basis, FPL customers will receive 100% of the Incentive Mechanism gain up to a threshold of $40 million. FPL will retain 60% and customers will receive 40% of incremental gains between $40 million and $100 million. FPL will retain 50% and customers will receive 50% of incremental gains in excess of $100 million.

(b) FPL will net economy sales and purchases in order to determine the impact of variable power plant O&M. If FPL executes more economy sales than economy purchases, FPL will recover the net amount of variable power plant O&M incurred in a given year. If economy purchases are greater than economy sales, FPL's customers will receive a credit for the net variable power plant O&M that has been saved in that year. The per-MWh variable power O&M rate used to calculate these costs shall be as described in FPL's 2017 Test Year MRFs filed with the 2016 Rate Petition, i.e., $0.65/MWh.

(c) Nothing in this Paragraph is intended to enlarge the jurisdiction of the Commission to approve cost recovery of investments beyond that authorized by Chapter 366, Fla. Stat.

16. FPL agrees to the termination of 100% of natural gas financial hedging prospectively for the Minimum Term and will make filings to implement such termination in Docket No. 160001-EI and subsequent fuel clause proceedings. FPL shall not be prohibited from filing a petition and proposed risk management plan with the Commission to address natural gas financial hedging following expiration of the Minimum Term. The Parties understand and intend that FPL will not enter into any new financial natural gas hedging contracts after the date on which this Agreement is executed, except as may be necessary

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for FPL to remain in compliance to the minimum extent practicable with the requirements of its currently approved Risk Management Plan.

17. (a) FPL is authorized to transfer to its FERC-regulated affiliate, Florida Southeast Connection ("FSC") the Martin-Riviera ("MR-RV") Lateral natural gas pipeline with all related equipment and inventory, upon a showing that such transfer will result in customer savings on a CPVRR basis pursuant to Paragraph 17(b). FPL will effectuate the transfer of the assets at their net book value as of the transaction date. Simultaneously with the transfer, FPL will contract with FSC to provide firm gas transportation from the Martin plant to the Riviera Beach plant in the same quantities currently available to FPL through its ownership of the MR-RV Lateral.

(b) If FPL negotiates contractual terms with FSC for firm gas transportation that would result in CPVRR savings to customers from the MR-RV Lateral transfer described in Paragraph 17(a), it will file a petition to confirm the cost-effectiveness of the transaction to customers. In that petition, FPL will request approval to implement a simultaneous change to lower base rates and adjust fuel rates to reflect the projected transportation charges. FPL will implement the base rate adjustment as a percentage reduction in base rates for every rate class. All Parties are free to participate in such proceeding.

18. FPL will implement a 50 MW battery storage pilot program ("Battery Storage Pilot") designed to enhance service for large commercial/industrial customers, small retail customers and large retail customers or to enhance operations of existing or planned solar facilities. The Parties to this Agreement will work cooperatively regarding the location of the battery storage projects; however, FPL shall ultimately be responsible for

determining the projects and locations that provide the most benefits at the time of installation. The cost to install battery storage projects pursuant to this Paragraph shall be reasonable and, on average, shall not exceed $2,300 per kWac. The Parties to this Agreement agree that the Battery Storage Pilot implementation in accordance with this Agreement and not in violation of any law are a prudent investment and provides benefits for customers. FPL will pursue cost recovery for the Battery Storage Pilot in its next general base rate case, and the Parties to this Agreement agree not to contest the prudence of the investment that complies with this Agreement.

19. FPL and interested Parties to this Agreement will jointly request a Commission workshop to address a Pilot Demand-Side Management Opt-Out program, including eligibility criteria, verification procedures, cost recovery and other implementation issues. Participation in the workshop and, if applicable, any Opt-Out program will not be limited to the Parties to this Agreement nor shall this Paragraph operate to impair the rights of any substantially affected person to seek additional or different relief as allowed by law.

20. FPL will evaluate whether it is reasonable and appropriate to offer a new tariff for customers who interconnect with an FPL distribution substation.

21. FPL in its next general base rate case will submit for informational purposes a cost of service study that compares revenue requirements by rate class between (a) implementing the Minimum Distribution System ("MDS") methodology at the requested revenue requirement increase, which study gives due consideration to the methodology applied by Tampa Electric Company in its last base rate case and (b) a situation that is identical to (a) in all other respects except that the MDS methodology is not implemented.

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22. No Party to this Agreement will request, support, or seek to impose a change in the application of any provision hereof. Except as provided in Paragraph 11, a Party to this Agreement will neither seek nor support any change in FPL's base rates or credits applied to customer bills, including limited, interim or any other rate decreases, that would take effect prior to expiration of the Minimum Term, except for any such reduction requested by FPL or as otherwise provided for in this Agreement. No party is prohibited from seeking interim, limited, or general base rate relief, or a change to credits, to be effective following the expiration of the Minimum Term.

23. Nothing in this Agreement will preclude FPL from filing and the Commission from approving any new or revised tariff provisions or rate schedules requested by FPL, provided that such tariff request does not increase any existing base rate component of a tariff or rate schedule during the Term unless the application of such new or revised tariff, service or rate schedule is optional to FPL's customers.

24. The provisions of this Agreement are contingent on approval of this Agreement in its entirety by the Commission without modification. The Parties agree that approval of this Agreement is in the public interest. The Parties further agree that they will support this Agreement and will not request or support any order, relief, outcome, or result in conflict with the terms of this Agreement in any administrative or judicial proceeding relating to, reviewing, or challenging the establishment, approval, adoption, or implementation of this Agreement or the subject matter hereof. No party will assert in any proceeding before the Commission or any court that this Agreement or any of the terms in the Agreement shall have any precedential value, except to enforce the provisions of this Agreement. Approval of this Agreement in its entirety will resolve all matters and issues

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in Docket Nos. 160021-EI, 160061-EI, 160062-EI and 160088-EI pursuant to and in accordance with Section 120.57(4), Florida Statutes. This docket will be closed effective on the date the Commission Order approving this Agreement is final, and no Party shall seek appellate review of any order issued in these Dockets.

25. This Agreement is dated as of October 6, 2016. It may be executed in counterpart originals, and a scanned .pdf copy of an original signature shall be deemed an original. Any person or entity that executes a signature page to this Agreement shall become and be deemed a Party with the full range of rights and responsibilities provided hereunder, notwithstanding that such person or entity is not listed in the first recital above and executes the signature page subsequent to the date of this Agreement, it being expressly understood that the addition of any such additional Party(ies) shall not disturb or diminish the benefits of this Agreement to any current Party.

26. All provisions of this Agreement survive the Minimum Term except Paragraphs 10 and 11.

In Witness Whereof, the Parties evidence their acceptance and agreement with the provisions of this Agreement by their signature.

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EXHIBIT A

Exhibit "A"
Revenue Increase by Rate Class - January 1, 2017 and January 1, 2018
($000)

Line No.	(1) Description of Source	(2) Total	(3) CILC-1D	(4) CILC-1G	(5) CILC-1T	(6) GS(T)-1	(7) GSCU-1	(8) GSD(T)-1	(9) GSLD(T)-1	(10) GSLD(T)-2
1	**REVENUE INCREASE**									
2	*January 1, 2017:*									
3	**ELECTRICITY SALES:**									
4	RETAIL BILLED SALES BASE REVENUES	403,829	9,565	102	4,826	7,065	108	65,893	39,947	8,625
5	RETAIL UNBILLED SALES REVENUES	55	1	0	1	3	0	13	5	1
6	*ELECTRICITY SALES INCREASE*	403,885	9,566	102	4,827	7,068	108	65,906	39,953	8,626
7										
8	**OTHER OPERATING REVENUE:**									
9	FIELD COLLECTION & LATE PAYMENT CHARGES	1,611	2	0		116	1	100	14	3
10	MISC SERVICE REVS - INITIAL CONNECT NEW PREMISE	682	0			183		21	0	0
11	MISC SERVICE REVS - RECONNECT AFTER NON PAYMENT	-3,877				-200		-8		
12	MISC SERVICE REVS - CONNECT / DISCONNECT EXIST. PREMISE	-3,395	0	0		-172		-20	0	0
13	MISC SVC REVS - CURRENT DIVERSION PENALTY	784				17		6	1	
14	MISC SERVICE REVS - OTHER BILLINGS	311	0	0	0	27	1	7	0	0
15	*OTHER OPERATING REVENUE INCREASE*	(3,885)	2	0	0	(29)	2	105	15	3
16										
17	***TOTAL INCREASE 1/1/2017***	**400,000**	**9,568**	**102**	**4,827**	**7,039**	**110**	**66,012**	**39,968**	**8,630**
18	**REVENUE INCREASE - CUMULATIVE**									
19	*January 1, 2018:*									
20	**ELECTRICITY SALES:**									
21	RETAIL BILLED SALES BASE REVENUES	616,897	13,008	173	6,214	20,991	117	97,453	59,831	13,048
22	RETAIL UNBILLED SALES REVENUES	165	4	0	2	9	0	40	16	4
23	*ELECTRICITY SALES INCREASE*	617,062	13,012	173	6,217	21,001	117	97,493	59,847	13,051
24										
25	**OTHER OPERATING REVENUE:**									
26	FIELD COLLECTION & LATE PAYMENT CHARGES	1,574	2	0		113	1	97	14	3
27	MISC SERVICE REVS - INITIAL CONNECT NEW PREMISE	748	0			201		23	0	0
28	MISC SERVICE REVS - RECONNECT AFTER NON PAYMENT	-3,877				-200		-8		
29	MISC SERVICE REVS - CONNECT / DISCONNECT EXIST. PREMISE	-3,395	0	0		-172		-20	0	0
30	MISC SVC REVS - CURRENT DIVERSION PENALTY	784				17		6	1	
31	MISC SERVICE REVS - OTHER BILLINGS	389	0	0	0	34	1	8	0	0
32	*OTHER OPERATING REVENUE INCREASE*	(3,777)	2	0	0	(7)	2	107	15	3
33										
34	*CUMULATIVE INCREASE 1/1/2018*	613,284	13,014	174	6,217	20,994	120	97,599	59,862	13,055
35	LESS 2017 INCREASE ADJUSTED FOR 2018 SALES	402,285	9,622	103	4,854	7,079	111	66,389	40,196	8,679
36	***TOTAL INCREMENTAL INCREASE 1/1/2018***	**211,000**	**3,391**	**70**	**1,363**	**13,915**	**9**	**31,211**	**19,666**	**4,376**

Notes:
Totals may not add due to rounding.
2018 present revenues for OL-1 were overstated by ~$3.8M (KO-20); this was corrected in the proposed settlement increase.

Exhibit "A"
Revenue Increase by Rate Class - January 1, 2017 and January 1, 2018
($000)

Line No.	(1) Description of Source	(2) GSLD(T)-3	(3) MET	(4) OL-1	(5) OS-2	(6) RS(T)-1	(7) SL-1	(8) SL-2	(9) SST-DST	(10) SST-TST
1	**REVENUE INCREASE**									
2	*January 1, 2017:*									
3	**ELECTRICITY SALES:**									
4	RETAIL BILLED SALES BASE REVENUES	656	120	392	86	264,397	1,878	43	26	102
5	RETAIL UNBILLED SALES REVENUES	0	0	0	0	29	0	0	0	0
6	*ELECTRICITY SALES INCREASE*	656	120	392	86	264,427	1,878	43	26	102
7										
8	**OTHER OPERATING REVENUE:**									
9	FIELD COLLECTION & LATE PAYMENT CHARGES	0		15	0	1,358	1	0	0	0
10	MISC SERVICE REVS - INITIAL CONNECT NEW PREMISE					478				
11	MISC SERVICE REVS - RECONNECT AFTER NON PAYMENT					-3,669				
12	MISC SERVICE REVS - CONNECT / DISCONNECT EXIST. PREMISE					-3,203				
13	MISC SVC REVS - CURRENT DIVERSION PENALTY					759				
14	MISC SERVICE REVS - OTHER BILLINGS	0	0	0	0	275	1	0	0	0
15	*OTHER OPERATING REVENUE INCREASE*	0	0	15	0	(4,002)	2	0	0	0
16										
17	***TOTAL INCREASE 1/1/2017***	**656**	**120**	**407**	**86**	**260,425**	**1,880**	43	**26**	**103**
18	**REVENUE INCREASE - CUMULATIVE**									
19	*January 1, 2018:*									
20	**ELECTRICITY SALES:**									
21	RETAIL BILLED SALES BASE REVENUES	682	141	(3,278)	130	406,060	2,120	45	26	136
22	RETAIL UNBILLED SALES REVENUES	0	0	0	0	88	1	0	0	0
23	*ELECTRICITY SALES INCREASE*	682	141	(3,278)	130	406,148	2,121	45	26	136
24										
25	**OTHER OPERATING REVENUE:**									
26	FIELD COLLECTION & LATE PAYMENT CHARGES	0		15	0	1,327	1	0	0	0
27	MISC SERVICE REVS - INITIAL CONNECT NEW PREMISE					524				
28	MISC SERVICE REVS - RECONNECT AFTER NON PAYMENT					-3,669				
29	MISC SERVICE REVS - CONNECT / DISCONNECT EXIST. PREMISE					-3,203				
30	MISC SVC REVS - CURRENT DIVERSION PENALTY					759				
31	MISC SERVICE REVS - OTHER BILLINGS	0	0	0	0	344	1	0	0	0
32	*OTHER OPERATING REVENUE INCREASE*	0	0	15	0	(3,918)	2	0	0	0
33										
34	*CUMULATIVE INCREASE 1/1/2018*	682	141	(3,263)	130	402,230	2,123	46	26	136
35	LESS 2017 INCREASE ADJUSTED FOR 2018 SALES	660	120	409	86	261,912	1,891	43	26	103
36	***TOTAL INCREMENTAL INCREASE 1/1/2018***	**22**	**20**	**(3,672)**	**44**	**140,318**	**232**	**2**	**0**	**33**

Notes:
Totals may not add due to rounding.
2018 present revenues for OL-1 were overstated by ~$3.8M (KO-20); this was corr

EXHIBIT B

2017 TARIFFS

PROPOSED AND LEGISLATIVE

SERVICE CHARGES

A $~~14.88~~25.00 service charge will be made for an initial connection.

A $~~17.66~~13.00 Reconnection Charge will be made for the reconnection of service after disconnection for nonpayment or violation of a rule or regulation.

A $~~14.88~~12.00 service charge will be made for the connection of an existing account.

A Returned Payment Charge as allowed by Florida Statute 68.065 shall apply for each check or draft dishonored by the bank upon which it is drawn. Termination of service shall not be made for failure to pay the Returned Payment Charge.

Charges for services due and rendered which are unpaid as of the past due date are subject to a Late Payment Charge of the greater of $5.00 or 1.5% applied to any past due unpaid balance of all accounts, except the accounts of federal, state, and local governmental entities, agencies, and instrumentalities. A Late Payment Charge shall be applied to the accounts of federal, state, and local governmental entities, agencies, and instrumentalities at a rate no greater than allowed, and in a manner permitted, by applicable law.

A $~~5.11~~49.00 Field Collection Charge will be added to a customer's bill for electric service when a field visit is made and payment is collected on a delinquent account. If service is disconnected, or a current receipt of payment is shown at the time of the field visit, this charge will not be applied.

FPL may waive the Reconnection Charge, Returned Payment Charge, Late Payment Charge and Field Collection Charge for Customers affected by natural disasters or during periods of declared emergencies or once in any twelve (12) month period for any Customer who would otherwise have had a satisfactory payment record (as defined in 25-6.097(2) F.A.C.), upon acceptance by FPL of a reasonable explanation justifying a waiver. In addition, FPL may waive the charge for connection of an existing account and the charge for an initial connection for new or existing Customers affected by natural disasters or during periods of declared emergencies.

CONSERVATION INSPECTIONS AND SERVICES

Residential Dwelling Units:
A charge of $15.00 will be made for a computerized energy analysis in which a comprehensive on-site evaluation of the residence is performed.

Commercial/Industrial:
There is no charge for conservation inspections and services (Business Energy Services).

TEMPORARY/CONSTRUCTION SERVICE

APPLICATION:

For ~~short term~~temporary electric service to installations such as fairs, exhibitions, construction projects, displays and similar installations.

SERVICE:

Single phase or three phase, 60 hertz at the available standard secondary distribution voltage. This service is available only when the Company has existing capacity in lines, transformers and other equipment at the requested point of delivery. The Customer's service entrance electrical cable shall not exceed 200 Amp capacity.

CHARGE:

The non-refundable charge must be paid in advance of installation of such facilities which shall include service and metering equipment.

Installing and removing overhead service and meter	$~~297.00~~367.00
Connecting and disconnecting Customer's service cable to Company's direct-buried underground facilities including installation and removal of meter	$~~175.00~~209.00

MONTHLY RATE:

This temporary service shall be billed under the appropriate rate schedule applicable to commercial and industrial type installations.

SPECIAL CONDITIONS:

If specific electrical service other than that stated above is required, the Company, at the Customer's request, will provide such service based on the estimated cost of labor for installing and removing such additional electrical equipment. This estimated cost will be ~~a contribution in aid of construction~~ payable in advance to the Company and subject to adjustment after removal of the required facilities. All Temporary/Construction services shall be subject to all of the applicable Rules, Regulations and Tariff charges of the Company, including Service Charges.

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective: January ~~2, 2013~~1, 2017

8 METERS

8.1 Location of Meters. The Company will determine the location of and install and properly maintain at its own expense such standard meter or meters and metering equipment as may be necessary to measure the electric service used by the Customer. The Customer will keep the meter location clear of obstructions at all times in order that the meter may be read and the metering equipment may be maintained or replaced. . If a Customer requests a different location for meter placement from that designated by the Company on initial application for service and the Company agrees that the different meter location is acceptable to the Company, the Customer shall pay the incremental cost of installing the meter at the different location. If an existing Customer requests relocation of an existing installed meter and the Company agrees that the different meter location is acceptable to the Company, the existing Customer shall pay the incremental cost of relocating the meter at the different location.

8.2 Setting and Removing Meters. None but duly authorized agents of the Company or persons authorized by law shall set or remove, turn on or turn off, or make any changes which will affect the accuracy of such meters. Connections to the Company's system are to be made only by its employees.

8.3 Tampering with Meters. Title to meters and metering equipment shall be and remain in the Company. Unauthorized connections to, or tampering with the Company's meter or meters, or meter seals, or indications or evidence thereof, subjects the Customer to immediate discontinuance of service, prosecution under the laws of Florida, adjustment of prior bills for services rendered, a tampering penalty of $200 for residential and non-demand commercial customers and $1,000 for all other customers, and reimbursement to the Company for all extra expenses incurred on this account.

8.4 Meter Tests. The Company employs every practicable means to maintain the commercial accuracy of its meters. Meter tests, and billing adjustments for inaccurate meters, are in accordance with the methods and procedure prescribed by the Florida Public Service Commission.

8.5 Failure of Meter. When a meter fails, or part or all of the metering equipment is destroyed, billing will be estimated based upon the registration of check metering equipment or other available data.

9 SERVICE STANDARDS

These "General Rules and Regulations for Electric Service" include, by reference, the terms and provisions of the Company's currently effective "Electric Service Standards" on file with the Florida Public Service Commission and is available on request. The "Standards" are primarily concerned with the electrical facilities and related equipment prior to installation and use. They explain the general character of electric service supplied, the meters, and other devices furnished by the Company, and the wiring and apparatus provided and installed by the Customer. The Standards serve as a guide to architects, engineers, electrical dealers and contractors in planning, installing, repairing or renewing electrical installations.

INDEX OF RATE SCHEDULES

RATE SCHEDULE	DESCRIPTION	SHEET NO.
BA	Billing Adjustments	8.030
SC	Storm Charge	8.040
GS-1	General Service - Non Demand (0-20 kW)	8.101
GST-1	General Service - Non Demand - Time of Use (0-20 kW)	8.103
GSD-1	General Service Demand (21-499 kW)	8.105
GSDT-1	General Service Demand - Time of Use (21-499 kW)	8.107
GSL	General Service Load Management Program	8.109
NSMR	Non-Standard Meter Rider	8.120
GSCU-1	General Service Constant Usage	8.122
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GSLD-2	General Service Large Demand (2000 kW +)	8.412
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HLFT	High Load Factor – Time of Use	8.425
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CST-2	Curtailable Service -Time of Use (~~2000 kW +~~69 kV or above)	8.440
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TR	Transformation Rider	8.820
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EFEDR	Existing Facility Economic Development Rider	8.900
CISR	Commercial/Industrial Service Rider	8.910
VSP	Voluntary Solar Partnership Pilot Program	8.930

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective: ~~July 21, 2015~~January 1, 2017

GENERAL SERVICE - NON DEMAND

RATE SCHEDULE: GS-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose with a demand of 20 kW or less.

SERVICE:

Single phase, 60 hertz and at any available standard distribution voltage. Three phase service will be provided without additional charge unless the Company's line extension policy is applicable thereto. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$~~7.75~~10.00
Non-Fuel Energy Charges:	
Base Energy Charge	~~5.384~~5.439 ¢ per kWh
Conservation Charge	See Sheet No. 8.030
Capacity Payment Charge	See Sheet No. 8.030
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
General Service Load Management Program (if applicable)	See Sheet No. 8.109
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum:	$~~7.75~~10.00
Non-Metered Accounts:	A Customer Charge of $~~1.00~~5.00 will apply to those accounts which are billed on an estimated basis and, at the Company's option, do not have an installed meter for measuring electric service. The minimum charge shall be~~$1.00.~~ $5.00.

SPECIAL PROVISIONS:

Energy used by commonly owned facilities of condominium, cooperative and homeowners' associations may qualify for the residential rate schedule as set forth on Sheet No. 8.211, Rider CU.

TERM OF SERVICE:

Not less than one (1) billing period.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE - NON DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: GST-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose with a demand of 20 kW or less. This is an optional rate available to General Service - Non Demand customers upon request subject to availability of meters.

SERVICE:

Single phase, 60 hertz and at any available standard distribution voltage. Three phase service will be provided without additional charge unless the Company's line extension policy is applicable thereto. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$~~15.21~~10.00	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~9.911~~10.038 ¢ per kWh	~~3.358~~3.441 ¢ per kWh
Conservation Charge	See Sheet No. 8.030	
Capacity Payment Charge	See Sheet No. 8.030	
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
General Service Load Management Program (if applicable)	See Sheet No. 8.109	
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	
Minimum:	$~~15.21~~10.00	

Initial service under this rate schedule shall begin on the first scheduled meter reading date following the installation of the time of use meter. ~~The Customer's first bill will reflect the lesser of the charges under Rate Schedule GS-1 or GST-1.~~

~~If the Customer elects to make a lump sum payment to the Company for time-of-use metering costs of $447.87, then the Customer Charge and Minimum Charge shall be $7.75.~~

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.104)

160001 Hearing Exhibits 00277

GENERAL SERVICE DEMAND

RATE SCHEDULE: GSD-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW and less than 500 kW. Customers with a Demand of 20 kW or less may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 21 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$~~20.24~~25.00
Demand Charges:	
Base Demand Charge	$~~8.26~~9.20 per kW
Capacity Payment Charge	See Sheet No. 8.030, per kW
Conservation Charge	See Sheet No. 8.030, per kW
Non-Fuel Energy Charges:	
Base Energy Charge	~~1.934~~2.035 ¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of 20 kW or less who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 21 kW times the Base Demand Charge; therefore the minimum charge is $~~193.70.~~218.20.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's thermal type meter or, at the Company's option, integrating type meter for the 30-minute period of Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: GSDT-1

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW and less than 500 kW. Customers with Demands of less than 21 kW may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 21 kW. This is an optional rate available to General Service Demand customers upon request subject to availability of meters.

SERVICE:
Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$~~26.97~~25.00
Demand Charges:	
Base Demand Charge	$~~8.26~~9.20 per kW of Demand occurring during the On-Peak period.
Capacity Payment Charge	See Sheet No. 8.030, per kW of Demand occurring during the On-Peak period.
Conservation Charge	See Sheet No. 8.030, per kW of Demand occurring during the On-Peak period.

Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~4.114~~4.142 ¢ per kWh	~~1.045~~1.102 ¢ per kWh
Environmental Charge	See Sheet No. 8.030	

Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 21 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 21 kW times the Base Demand Charge, therefore the minimum charge is $~~200.43. If the Customer elects to make a lump sum payment to the Company for time-of-use metering costs of $404.71, then the Customer Charge and the Minimum Charge shall be $20.24 and $193.70, respectively.~~218.20.

RATING PERIODS:
On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.108)

160001 Hearing Exhibits 00279

GENERAL SERVICE CONSTANT USAGE

RATE SCHEDULE: GSCU-1

AVAILABLE:

In all territory served.

APPLICATION:

Available to General Service - Non Demand customers that maintain a relatively constant kWh usage, and a demand of 20 kW or less. Eligibility is restricted to General Service customers whose Maximum kWh Per Service Day, over the current and prior 23 months, is within 5% of their average monthly kWh per service days calculated over the same 24-month period. Customers under this Rate Schedule shall enter into a General Service Constant Use Agreement. This is an optional Rate Schedule available to General Service customers upon request.

SERVICE:

Single phase, 60 hertz and at any available standard distribution voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$~~13.50~~14.00
Non-Fuel Energy Charges:	
Base Energy Charge*	~~3.352~~3.507 ¢ per Constant Usage kWh
Conservation Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Capacity Payment Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Environmental Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Additional Charges:	
Fuel Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Storm Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

* The fuel, storm and non-fuel energy charges will be assessed on the Constant Usage kWh

TERM OF SERVICE:

Initial term of service under this rate schedule shall be not less than one (1) billing period, unless there is a termination of service due to a Customer's violation of the General Service Constant Usage Agreement. Upon the Customer's violation of any of the terms of the General Service Constant Usage Agreement, service under this Rate Schedule will be terminated immediately. To terminate service, either party must provide thirty (30) days written notice to the other party prior to the desired termination date. Absent such notice, the term of service shall automatically be extended another billing period. In addition, if service under this Rate Schedule is terminated by either the Customer or the Company, the account may not resume service under this Rate Schedule for a period of at least one (1) year.

DEFINITIONS:

kWh Per Service Day – the total kWh in billing month divided by the number of days in the billing month

Maximum kWh Per Service Day - the highest kWh Per Service Day experienced over the current and prior 23 month billing periods

Constant Usage kWh – the Maximum kWh Per Service Day multiplied by the number of service days in the current billing period

(Continued on Sheet 8.123)

RESIDENTIAL SERVICE

RATE SCHEDULE: RS-1

AVAILABLE:

In all territory served.

APPLICATION:

For service for all domestic purposes in individually metered dwelling units and in duplexes and triplexes, including the separately-metered non-commercial facilities of a residential Customer (i.e., garages, water pumps, etc.). Also for service to commonly-owned facilities of condominium, cooperative and homeowners' associations as set forth on Sheet No. 8.211, Rider CU.

SERVICE:

Single phase, 60 hertz at available standard distribution voltage. Three phase service may be furnished but only under special arrangements. All residential service required on the premises by Customer shall be supplied through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$7.87
Non-Fuel Charges:	
Base Energy Charge:	
First 1,000 kWh	~~4.913~~5.562 ¢ per kWh
All additional kWh	~~6.038~~6.562 ¢ per kWh
Conservation Charge	See Sheet No. 8.030
Capacity Payment Charge	See Sheet No. 8.030
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Residential Load Control Program (if applicable)	See Sheet No. 8.217
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum:	$7.87

TERM OF SERVICE:

Not less than one (1) billing period.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

RESIDENTIAL TIME OF USE RIDER – RTR-1
(OPTIONAL)

RIDER: RTR-1

AVAILABLE:
In all territory served.

APPLICATION:

For service for all domestic purposes in individually metered dwelling units and in duplexes and triplexes, including the separately-metered non-commercial facilities of a residential Customer (i.e., garages, water pumps, etc.). Also for service to commonly-owned facilities of condominium, cooperative and homeowners' associations as set forth on Sheet No. 8.211, Rider CU. This is an optional rider available to residential customers served under the RS-1 Rate Schedule subject to availability of meters. Customers taking service under RTR-1 are not eligible for service under Rate Schedule RLP.

SERVICE:
Single phase, 60 hertz at available standard distribution voltage. Three phase may be supplied but only under special arrangements. All residential service required on the premises by Customer shall be supplied through one meter. Resale of service is not permitted hereunder.

Initial service under this rate schedule shall begin on the first scheduled meter reading date following the installation of the time of use meter. The Customer's first bill will reflect the lesser of the charges under Rate Schedule RS-1 or RTR-1.

MONTHLY RATE:

Except for the Customer Charge, all rates and charges under Rate Schedule RS-1 shall apply. In addition, the RTR-1 Customer Charge, the RTR-1 Base Energy and Fuel Charges and Credits applicable to on and off peak usage shall apply.

Customer Charge:	$~~12.36~~7.87	
Base Energy Charges/Credits:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~9.154~~9.937 ¢ per kWh	(~~4.072~~4.420) ¢ per kWh
Additional Charges/Credits:		
RTR Fuel Charge/Credit	See Sheet No. 8.030	
Minimum:	$~~12.36~~7.87	

~~If the Customer elects to make a lump sum payment to the Company for time of use metering costs of $269.80, then the Customer Charge and Minimum Charge shall be $7.87.~~

RATING PERIODS:
On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.204)

160001 Hearing Exhibits 00282

GENERAL SERVICE LARGE DEMAND

RATE SCHEDULE: GSLD-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer with a measured demand of 500 kW and less than 2,000 kW. Customers with demands of less than 500 kW may enter an agreement for service under this Rate Schedule based on a Demand Charge for a minimum of 500 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$~~61.83~~75.00
Demand Charges:	
Base Demand Charge	$~~9.47~~11.00 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	~~1.430~~1.585 ¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charges	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is $~~4,796.83.~~5,575.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's thermal type meter or, at the Company's option, integrating type meter for the 30-minute period of Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE LARGE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE GSLDT-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer with a measured demand of 500 kW and less than 2,000 kW. Customers with demands of less than 500 kW may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 500 kW. This is an optional rate available to General Service Large Demand customers upon request subject to availability of meters.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$~~61.83~~75.00	
Demand Charges:		
Base Demand Charge	$~~9.47~~11.00 per kW of Demand occurring during the On-Peak period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~2.380~~2.597 ¢ per kWh	~~1.035~~1.143 ¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is $~~4,796.83.~~5,575.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.321)

160001 Hearing Exhibits 00284

CURTAILABLE SERVICE
(OPTIONAL)

RATE SCHEDULE: CS-1

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-1 (500 kW - 1,999 kW) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. Customers with demands of at least 200 kW but less than 500 kW may enter an agreement for service under this Rate Schedule based on a Demand Charge for a minimum of 500 kW.

SERVICE:
Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$~~89.93~~100.00
Demand Charges:	
Base Demand Charge	$~~9.47~~11.00 per kW of Demand.
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	~~1.430~~1.585 ¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is $~~4,824.93.~~5,600.00.

CURTAILMENT CREDITS:
A monthly credit of ($1.93) per kW is allowed based on the current Non-Firm Demand. The Customer has the option to revise the Firm Demand once during the initial twelve (12) month period. Thereafter, subject to the Term of Service and/or the Provisions for Early Termination, a change to the Firm Demand may be made provided that the revision does not decrease the total amount of Non-Firm Demand during the lesser of: (i) the average of the previous 12 months; or (ii) the average of the number of billing months under this Rate Schedule.

CHARGES FOR NON-COMPLIANCE OF CURTAILMENT DEMAND:
If the Customer records a higher Demand during the current Curtailment Period than the Firm Demand, the Customer will be:

1. Rebilled at 1.93/kW for the prior 36 months or the number of months since the prior Curtailment Period, whichever is less, and
2. Billed a penalty charge of $4.16 kW for the current month.

The kW used for both the rebilling and penalty charge calculations is determined by taking the difference between the maximum Demand during the current Curtailment Period and the Firm Demand for a Curtailment Period.

(Continued on Sheet No. 8.331)

160001 Hearing Exhibits 00285

CURTAILABLE SERVICE - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: CST-1

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-1 (500 kW - 1,999 kW) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. This is an optional Rate Schedule available to Curtailable General Service Customers upon request. Customers with demands of at least 200 kW but less than 500 kW may enter an agreement for service under this Rate Schedule based on a Demand Charge for a minimum of 500 kW

SERVICE:

Single or three phase, 60 hertz and at any available distribution standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$~~89.93~~100.00	
Demand Charges:		
Base Demand Charge	$~~9.47~~11.00 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~2.380~~2.597 ¢ per kWh	~~1.035~~1.143 ¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is $~~4,824.93.~~5,600.00.

RATING PERIODS:

On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.341)

160001 Hearing Exhibits 00286

GENERAL SERVICE LARGE DEMAND

RATE SCHEDULE: GSLD-2

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer with a measured demand of 2,000 kW or more. Customers with demands of less than 2,000 kW may enter an agreement for service under this schedule based on a demand charge for a minimum of 2,000 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$~~219.22~~225.00
Demand Charges:	
Base Demand Charge	$~~9.80~~11.40 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	~~1.287~~1.427 ¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a demand of less than 2,000 kW who enter an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is $~~19,819.22~~23,025.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's metering equipment, for the 30-minute period of the Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE LARGE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: GSLDT-2

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer who has established a measured demand of 2,000 kW or more. Customers with demands of less than 2,000 kW may enter an agreement for service under this schedule based on a demand charge for a minimum of 2,000 kW.

SERVICE:

Three phase, 60 hertz and at any available standard ~~secondary or~~ distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$~~219.22~~225.00	
Demand Charges:		
Base Demand Charge	$~~9.80~~ 11.40 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~2.041~~2.227 ¢ per kWh	~~1.003~~1.112 ¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a demand of less than 2,000 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is $~~19,819.22~~23,025.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.421)

160001 Hearing Exhibits 00288

HIGH LOAD FACTOR – TIME OF USE
(OPTIONAL)

RATE SCHEDULE: HLFT

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW. This is an optional rate schedule available to customers otherwise served under the GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, or GSLDT-2 Rate Schedules.

SERVICE:
Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

	HLFT-1 21-499 kW	HLFT-2 500-1,999 kW	HLFT-3 2,000 kW or greater
Annual Maximum Demand			
Customer Charge: ~~$219.22~~225.00	~~$26.97~~25.00	~~$61.83~~75.00	
Demand Charges:			
On-peak Demand Charge ~~$10.03~~11.60	~~$9.83~~10.80	~~$10.03~~11.60	
Maximum Demand Charge ~~$2.24~~2.50	~~$2.14~~2.30	~~$2.24~~2.50	
Capacity Payment Charge	See Sheet No. 8.030, per kW of On-Peak Demand		
Conservation Charge	See Sheet No. 8.030, per kW of On-Peak Demand		
Non-Fuel Energy Charges:			
On-Peak Period per kWh ~~0.810~~0.903 ¢	~~1.617~~1.738 ¢	~~0.885~~1.003 ¢	
Off-Peak Period per kWh	~~1.045~~1.102 ¢	~~0.885~~0.977 ¢	~~0.810~~0.898 ¢
Environmental Charge	See Sheet No. 8.030		
Additional Charges			
Fuel Charge	See Sheet No. 8.030		
Storm Charge	See Sheet No. 8.040		
Franchise Fee	See Sheet No. 8.031		
Tax Clause	See Sheet No. 8.031		

Minimum Charge: The Customer Charge plus the currently effective Demand Charges.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.426)

160001 Hearing Exhibits 00289

CURTAILABLE SERVICE
(OPTIONAL)

RATE SCHEDULE: CS-2

AVAILABLE:

In all territory served.

APPLICATION:

For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-2 (2,000 kW and above) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. Customers with demands of less than 2,000 kW may enter an Agreement for service under this schedule based on a Demand Charge for a minimum of 2,000 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$~~247.32~~250.00
Demand Charges:	
Base Demand Charge	$~~9.80~~ 11.40 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	~~1.287~~ 1.427 ¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 2,000 kW who enter an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is $~~19,847.32.~~23,050.

CURTAILMENT CREDITS:

A monthly credit of ($1.93) per kW is allowed based on the current Non-Firm Demand. The Customer has the option to revise the Firm Demand once during the initial twelve (12) month period. Thereafter, subject to the Term of Service and/or the Provisions for Early Termination, a change to the Firm Demand may be made provided that the revision does not decrease the total amount of Non-Firm Demand during the lesser of: (i) the average of the previous 12 months; or (ii) the average of the number of billing months under this Rate Schedule.

CHARGES FOR NON-COMPLIANCE OF CURTAILMENT DEMAND:

If the Customer records a higher Demand during the current period than the Firm Demand, then the Customer will be:

1. Rebilled at $1.93 /kW for the prior 36 months or the number of months since the prior Curtailment Period, whichever is less, and
2. Billed a penalty charge of $4.16 /kW for the current month.

The kW used for both the rebilling and penalty charge calculations is determined by taking the difference between the maximum Demand during the current Curtailment Period and the contracted Firm Demand for a Curtailment Period.

(Continued on Sheet No. 8.433)

160001 Hearing Exhibits 00290

CURTAILABLE SERVICE - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: CST-2

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLDT-2 (2,000 kW and above) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. Customers with demands of less than 2,000 kW may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 2,000 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$~~247.32~~250.00	
Demand Charges:		
Base Demand Charge	$~~9.80~~11.40 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~2.041~~2.227 ¢ per kWh	~~1.003~~1.112 ¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 2,000 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is $~~19,847.32~~23,050.

RATING PERIODS:

On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.441)

160001 Hearing Exhibits 00291

CURTAILABLE SERVICE - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: CST-3

AVAILABLE:

In all territory served.

APPLICATION:

For any commercial or industrial Customer who qualifies for Rate Schedule GSLDT-3 and will curtail this Demand by 200 kW or more upon request of the Company from time to time.

SERVICE:

Three phase, 60 hertz at the available transmission voltage of 69 kV or higher. The Customer will provide and maintain all transformers and related facilities necessary for handling and utilizing the power and energy delivered hereunder. All service required by the Customer at each separate point of delivery served hereunder shall be furnished through one meter at, or compensated to, the available transmission voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$~~1,649.04~~2,025.00	
Demand Charges:		
Base Demand Charge	$~~7.69~~9.30 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030.1	
Conservation Charge	See Sheet No. 8.030.1	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~1.043~~1.227 ¢ per kWh	~~0.892~~1.019 ¢ per kWh
Environmental Charge	See Sheet No. 8.030.1	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030.1	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.543)

160001 Hearing Exhibits 00292

CURTAILABLE SERVICE
(OPTIONAL)

RATE SCHEDULE: CS-3

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-3 and will curtail this Demand by 200 kW or more upon request of the Company from time to time.

SERVICE:
Three phase, 60 hertz at the available transmission voltage of 69 kV or higher. The Customer will provide and maintain all transformers and related facilities necessary for handling and utilizing the power and energy delivered hereunder. All service required by the Customer at each separate point of delivery served hereunder shall be furnished through one meter at, or compensated to, the available transmission voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$~~1,649.04~~2,025.00
Demand Charges:	
Base Demand Charge	$~~7.69~~ 9.30 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030.1
Conservation Charge	See Sheet No. 8.030.1
Non-Fuel Energy Charges:	
Base Energy Charge	~~0.932~~ 1.069 ¢ per kWh
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum Charge: The Customer Charge plus the charge for the currently effective Base Demand.

CURTAILMENT CREDITS:
A monthly credit of ($1.93) per kW is allowed based on the current Non-Firm Demand. The Customer has the option to revise the Firm Demand once during the initial twelve (12) month period. Thereafter, subject to the Term of Service and/or the Provisions for Early Termination, a change to the Firm Demand may be made provided that the revision does not decrease the total amount of Non-Firm Demand during the lesser of: (i) the average of the previous 12 months; or (ii) the average of the number of billing months under this Rate Schedule.

CHARGES FOR NON-COMPLIANCE OF CURTAILMENT DEMAND:

If the Customer records a higher Demand during the current Curtailment Period than the Firm Demand, then the Customer will be:

1. Rebilled at $1.93 /kW for the prior 36 months or the number of months since the prior Curtailment Period, whichever is less, and
2. Billed a penalty charge of $4.16 /kW for the current month.

The kW used for both the rebilling and penalty charge calculations is determined by taking the difference between the maximum Demand during the current Curtailment Period and the Firm Demand for a Curtailment Period.

(Continued on Sheet No. 8.546)

160001 Hearing Exhibits 00293

GENERAL SERVICE LARGE DEMAND

RATE SCHEDULE: GSLD-3

AVAILABLE:

In all territory served.

APPLICATION:

For service ~~to~~required for commercial or industrial ~~Customer installations when the Demand of each installation is at least 2,000 kW at the available~~lighting, power and any other purpose to any Customer who has service supplied at a transmission voltage of 69 kV or higher.

SERVICE:

Three phase, 60 hertz at the available transmission voltage of 69 kV or higher. The Customer will provide and maintain all transformers and related facilities necessary for handling and utilizing the power and energy delivered hereunder. All service required by the Customer at each separate point of delivery served hereunder shall be furnished through one meter at, or compensated to, the available transmission voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$~~1,620.94~~2,000.00
Demand Charges:	
Base Demand Charge	$~~7.69~~ 9.30 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030.1
Conservation Charge	See Sheet No. 8.030.1
Non-Fuel Energy Charges:	
Base Energy Charge	~~0.932~~ 1.069¢ per kWh
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's metering equipment for the 30-minute period of the Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE LARGE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: GSLDT-3

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose to any Customer who has ~~established a measured demand of 2,000 kW or more. Customers with demands of less than 2,000 kW may enter an agreement for service under this schedule based on a minimum demand charge of 2,000 kW times the maximum demand charge at the available~~service supplied at a transmission voltage of 69 kV or higher.

SERVICE:

Three phase, 60 hertz at the available transmission voltage of 69 kV or higher. The Customer will provide and maintain all transformers and related facilities necessary for handling and utilizing the power and energy delivered hereunder. All service required by the Customer at each separate point of delivery served hereunder shall be furnished through one meter at, or compensated to, the available transmission voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$~~1,620.94~~2,000.00	
Demand Charges:		
Base Demand Charge	$~~7.69~~ 9.30 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030.1	
Conservation Charge	See Sheet No. 8.030.1	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	1.217 ~~1.043~~ ¢ per kWh	~~0.892~~ 1.016 ¢ per kWh
Environmental Charge	See Sheet No. 8.030.1	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030.1	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand.

RATING PERIODS:

On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.553)

160001 Hearing Exhibits 00295

SPORTS FIELD SERVICE
(Closed Schedule)

RATE SCHEDULE: OS-2

AVAILABLE:

In all territory served.

APPLICATION:

This is a transitional rate available to municipal, county and school board accounts for the operation of a football, baseball or other playground, or civic or community auditorium, when all such service is taken at the available primary distribution voltage at a single point of delivery and measured through one meter, and who were active as of October 4, 1981. Customer may also elect to receive service from other appropriate rate schedules.

LIMITATION OF SERVICE:

Offices, concessions, businesses or space occupied by tenants, other than areas directly related to the operations above specified, are excluded hereunder and shall be separately served by the Company at utilization voltage. Not applicable when Rider TR is used.

MONTHLY RATE:

Customer Charge:	$~~115.80~~125.00
Non-Fuel Energy Charges:	
Base Energy Charge	~~6.784~~7.455 ¢ per kWh
Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum Charge:	$~~115.80~~125.00

TERM OF SERVICE:

Pending termination by Florida Public Service Commission Order.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

METROPOLITAN TRANSIT SERVICE

RATE SCHEDULE: MET

AVAILABLE:

For electric service to Metropolitan Miami-Dade County Electric Transit System (METRORAIL) at each point of delivery required for the operation of an electric transit system on continuous and contiguous rights-of-way.

APPLICATION:

Service to be supplied will be three phase, 60 hertz and at the standard primary distribution voltage of 13,200 volts. All service required by Customer at each separate point of delivery served hereunder shall be furnished through one meter reflecting delivery at primary voltage. Resale of service is not permitted hereunder. Rider TR or a voltage discount is not applicable.

MONTHLY RATE:

Customer Charge:	$~~449.67~~550.00
Demand Charges:	
Base Demand Charge	$~~11.85~~ 12.70 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030.1
Conservation Charge	See Sheet No. 8.030.1
Non-Fuel Energy Charges:	
Base Energy Charge	~~1.661~~ 1.692 ¢ per kWh
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand.

DEMAND:

The billing Demand is the kW, at each point of delivery, to the nearest whole kW, as determined from the Company's recording type metering equipment, for the period coincident with the 30-minute period of the electric rail transit system's greatest use supplied by the Company during the month adjusted for power factor.

BILLING:

Each point of delivery shall be separately billed according to the monthly charges as stated herein. All billing units related to charges under this rate schedule shall be determined from metering data on a monthly basis and determined for each point of delivery on the same monthly billing cycle day.

TERMS OF SERVICE

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective: ~~April~~January 1, ~~2016~~2017

(Continued from Sheet No. 8.650)

MONTHLY RATE:

Delivery Voltage Level	Distribution below 69 kV		69 kV & above	
	CILC-1(G)	CILC-1(D)	CILC-1(T)	
Maximum Demand Level	200-499 kW	500 kW & above		
Customer Charge:	$~~112.42~~ 125.00		$~~168.63~~225.00	
$~~2,220.26~~2,225.00				
Demand Charges:				
Base Demand Charges:				
per kW of Maximum Demand	$~~3.82~~3.90		$~~3.49~~4.00	None
per kW of Load Control On-Peak Demand	$~~1.97~~2.60		$~~1.97~~2.90	
$~~1.97~~3.00				
per kW of Firm On-Peak Demand	$~~8.73~~9.60		$~~8.51~~10.50	
$~~8.65~~11.20				
Capacity Payment and Conservation Charge:				
CILC-1(G)	See Sheet No. 8.030.1			
CILC-1(D)	See Sheet No. 8.030.1			
CILC-1(T)	See Sheet No. 8.030.1			
Non-Fuel Energy Charges:				
Base Energy Charges:				
On-Peak Period charge per kWh	~~1.425~~1.480 ¢		~~0.822~~0.954 ¢	
~~0.731~~0.900 ¢				
Off-Peak Period charge per kWh	~~1.425~~1.480 ¢		~~0.822~~0.954 ¢	
~~0.731~~0.900 ¢				
Environmental Charge	See Sheet No. 8.030.1			
Additional Charges:				
Fuel Charge	See Sheet No. 8.030.1			
Storm Charge	See Sheet No. 8.040			
Franchise Fee	See Sheet No. 8.031			
Tax Clause	See Sheet No. 8.031			

Minimum: The Customer Charge plus the Base Demand Charges.

(Continued on Sheet No. 8.652)

160001 Hearing Exhibits 00298

COMMERCIAL/INDUSTRIAL DEMAND REDUCTION RIDER (CDR)
(OPTIONAL)

AVAILABLE:

In all territory served. Available to any commercial or industrial customer receiving service under Rate Schedules GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, or HLFT through the execution of a Commercial/Industrial Demand Reduction Rider Agreement in which the load control provisions of this rider can feasibly be applied.

LIMITATION OF AVAILABILITY:

This Rider may be modified or withdrawn subject to determinations made under Commission Rules 25-17.0021(4), F.A.C., Goals for Electric Utilities and 25-6.0438, F.A.C., Non-Firm Electric Service - Terms and Conditions or any other Commission determination.

APPLICATION:

For electric service provided to any commercial or industrial customer receiving service under Rate Schedule GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, or HLFT who as a part of the Commercial/Industrial Demand Reduction Rider Agreement between the Customer and the Company, agrees to allow the Company to control at least 200 kW of the Customer's load, or agrees to operate Backup Generation Equipment (see Definitions) and designate (if applicable) additional controllable demand to serve at least 200 kW of the Customer's own load during periods when the Company is controlling load. A Customer shall enter into a Commercial/Industrial Reduction Demand Rider Agreement with the Company to be eligible for this Rider. To establish the initial qualification for this Rider, the Customer must have had a Utility Controlled Demand during the summer Controllable Rating Period (April 1 through October 31) for at least three out of seven months of at least 200 kW greater than the Firm Demand level specified in Section 4 of the Commercial/Industrial Demand Reduction Rider Agreement. The Utility Controlled Demand shall not be served on a firm service basis until service has been terminated under this Rider.

LIMITATION OF SERVICE:

Customers participating in the General Service Load Management Program (FPL "Business On Call" Program) are not eligible for this Rider.

MONTHLY RATE:

All rates and charges under Rate Schedules GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, HLFT shall apply. In addition, the applicable Monthly Administrative Adder and Utility Controlled Demand Credit shall apply.

MONTHLY ADMINISTRATIVE ADDER:

Rate Schedule	Adder
GSD-1	$~~84.31~~100.00
GSDT-1, HLFT (21-499 kW)	$~~84.31~~100.00
GSLD-1, GSLDT-1, HLFT (500-1,999 kW)	$~~140.52~~150.00
GSLD-2, GSLDT-2, HLFT (2,000 kW or greater)	$~~56.21~~75.00
GSLD-3, GSLDT-3	$~~533.99~~225.00

UTILITY CONTROLLED DEMAND CREDIT:

A monthly credit of ($8.20) per kW is allowed based on the Customer's Utility Controlled Demand.

UTILITY CONTROLLED DEMAND:

The Utility Controlled Demand for a month in which there are no load control events during the Controllable Rating Period shall be the sum of the Customer's kWh usage during the hours of the applicable Controllable Rating Period, divided by the total number of hours in the applicable Controllable Rating Period, less the Customer's Firm Demand.

In the event of Load Control occurring during the Controllable Rating Period, the Utility Controlled Demand shall be the sum of the Customer's kWh usage during the hours of the applicable Controllable Rating Period less the sum of the Customer's kWh usage during the Load Control Period, divided by the number of non-load control hours occurring during the applicable Controllable Rating Period, less the Customer's Firm Demand.

(Continued on Sheet No. 8.681)

160001 Hearing Exhibits 00299

STREET LIGHTING

RATE SCHEDULE: SL-1

AVAILABLE:

In all territory served.

APPLICATION:

For lighting streets and roadways, whether public or private, which are thoroughfares for normal flow of vehicular traffic. Lighting for other applications such as: municipally and privately-owned parking lots; parks and recreational areas; or any other area not expressly defined above, is not permitted under this schedule~~.~~ except for lighting in such an application that was already under this schedule prior to July 9, 1992. Lamp replacement and energy-only service is available to existing customer facilities taking service under this rate prior to January 1, 2017.

TYPE OF INSTALLATION:

FPL-owned fixtures normally will be mounted on poles of FPL's existing distribution system and served from overhead wires. On request of the Customer, FPL will provide special poles or underground wires at the charges specified below. Customer-owned systems will be of a standard type and design, permitting service and lamp replacement at no abnormal cost to FPL.

SERVICE:

Service includes lamp renewals, patrol, energy from dusk each day until dawn the following day and maintenance of FPL-owned Street Lighting Systems.

LIMITATION OF SERVICE:

For Mercury Vapor, Fluorescent and Incandescent luminaires, no additions or changes in specified lumen output on existing installations will be permitted under this schedule after October 4, 1981 except where such additional lights are required in order to match existing installations.

Stand-by or resale service is not permitted hereunder.

CUSTOMER CONTRIBUTIONS:

A Contribution-in-Aid-of-Construction (CIAC) will be required for:

a) the differential cost between employing rapid construction techniques in trenching, backfilling and pole installation work where no obstructions exist, and the added cost to overcome obstructions such as sprinkler systems, paved surfaces (such as sidewalks, curbs, gutters, and roadways), landscaping, sodding and other obstructions encountered along the Street Light System installation route, including repair and replacement. If the Customer elects to perform work such as trenching and restoration, they will be reimbursed by FPL with a credit (not to exceed the total CIAC cost) for the value of this work as determined by FPL;

b) the installation cost of any new overhead distribution facilities and/or the cost of alterations to existing distribution facilities which are required in order to serve the Street Lighting System less four (4) times the additional annual non-fuel energy revenue generated by the installation or alteration of the Street Lighting System, plus where underground facilities are installed, the differential installation cost between underground and overhead distribution facilities.

These costs shall be paid by the Customer prior to the initiation of any construction work by FPL. The Customer shall also pay any additional costs associated with design modifications requested after the original estimate has been made.

(Continued on Sheet No. 8.716)

160001 Hearing Exhibits 00300

(Continued from Sheet No. 8.715)

REMOVAL OF FACILITIES:

If Street Lighting facilities are removed either by Customer request or termination or breach of the agreement, the Customer shall pay FPL an amount equal to the original installed cost of the removed facilities less any salvage value and any depreciation (based on current depreciation rates as approved by the Florida Public Service Commission) plus removal cost.

MONTHLY RATE:

Luminaire Type		Lamp Size Initial Lumens/Watts		kWh/Mo. Estimate	Charge for FPL-Owned Unit ($) Fixtures	Maintenance	Energy Non-Fuel **	Total ***	Charge for Customer-Owned Unit $) **** Relamping/ Energy	Energy Only
High Pressure Sodium Vapor		6,300	70	29	$~~3.74~~3.89	~~1.76~~1.85	~~0.77~~0.83	~~6.27~~6.57	$~~2.56~~2.69	$~~0.77~~0.83
"	"	9,500	100	41	$~~3.81~~3.96	~~1.77~~1.86	~~1.09~~1.17	~~6.67~~6.99	$~~2.89~~3.04	$~~1.09~~1.17
"	"	16,000	150	60	$~~3.93~~4.08	~~1.80~~1.89	~~1.59~~1.71	~~7.32~~7.68	$~~3.42~~3.61	$~~1.59~~1.71
"	"	22,000	200	88	$~~5.95~~6.18	~~2.29~~2.41	~~2.33~~2.51	~~10.57~~11.10	$~~4.63~~4.90	$~~2.33~~2.51
"	"	50,000	400	168	$~~6.01~~6.24	~~2.30~~2.42	~~4.46~~4.79	~~12.77~~13.45	$~~6.77~~7.19	$~~4.46~~4.79
"	"	* 27,500	250	116	$~~6.33~~	~~2.50~~	~~3.08~~	~~11.91~~	~~$5.58~~	~~$3.08~~6.58
2.63	3.31	12.52	$5.91	$3.31						
"	"	* 140,000	1,000	411	$~~9.53~~	~~4.48~~	~~10.90~~	~~24.91~~	~~$15.47~~9.90	4.71
11.71		26.32	$16.46	$~~10.90~~11.71						
Mercury Vapor	*	6,000	140	62	$~~2.95~~3.07	~~1.58~~1.66	~~1.64~~1.77	~~6.17~~6.50	$~~3.25~~3.44	$~~1.64~~1.77
"	*	8,600	175	77	$~~3.00~~3.12	~~1.58~~	~~2.04~~	~~6.62~~	~~$3.65~~1.66	2.19 6.97
$3.86		$~~2.04~~2.19								
"	*	11,500	250	104	$~~5.01~~5.21	~~2.28~~2.40	~~2.76~~2.96	~~10.05~~10.57	$~~5.08~~5.37	$~~2.76~~2.96
"	*	21,500	400	160	$~~4.99~~5.18	~~2.24~~2.36	~~4.24~~4.56	~~11.47~~12.10	$~~6.52~~6.93	$~~4.24~~4.56

* These units are closed to new FPL installations.
** The non-fuel energy charge is ~~2.652~~2.850 ¢ per kWh.
*** Bills rendered based on "Total" charge. Unbundling of charges is not permitted.
**** New customer-owned facilities are closed to this rate effective January 1, ~~2017.~~2017.

Charges for other FPL-owned facilities:

Wood pole used only for the street lighting system	$~~4.54~~4.92
Concrete pole used only for the street lighting system	$~~6.23~~6.74
Fiberglass pole used only for the street lighting system	$~~7.37~~7.98
Steel pole used only for the street lighting system *	$~~6.23~~6.74
Underground conductors not under paving	~~3.56~~3.810 ¢ per foot
Underground conductors under paving	~~8.71~~9.310 ¢ per foot

The Underground conductors under paving charge will not apply where a CIAC is paid pursuant to section "a)" under "Customer Contributions." The Underground conductors not under paving charge will apply in these situations.

(Continued on Sheet No. 8.717)

160001 Hearing Exhibits 00301

(Continued from Sheet No. 8.716)

On Customer-owned Street Lighting Systems, where Customer contracts to relamp at no cost to FPL, the Monthly Rate for non-fuel energy shall be ~~2.755~~2.850 ¢ per kWh of estimated usage of each unit plus adjustments. On Street Lighting Systems, where the Customer elects to install Customer-owned monitoring systems, the Monthly Rate for non-fuel energy shall be ~~2.755~~2.850 ¢ per kWh of estimated usage of each monitoring unit plus adjustments. The minimum monthly kWh per monitoring device will be 1 kilowatt-hour per month, and the maximum monthly kWh per monitoring device will be 5 kilowatt-hours per month.

During the initial installation period:
Facilities in service for 15 days or less will not be billed;
Facilities in service for 16 days or more will be billed for a full month.

WILLFUL DAMAGE:

Upon the **second** occurrence of willful damage to any FPL-owned facilities, the Customer will be responsible for the cost incurred for repair or replacement. If the lighting fixture is damaged, based on prior written instructions from the Customer, FPL will:

a) Replace the fixture with a shielded cutoff cobrahead. The Customer shall pay $280.00 for the shield plus all associated costs. However, if the Customer chooses to have the shield installed after the first occurrence, the Customer shall only pay the $280.00 cost of the shield; or

b) Replace with a like unshielded fixture. For this, and each subsequent occurrence, the Customer shall pay the costs specified under "Removal of Facilities"; or

c) Terminate service to the fixture.

Option selection shall be made by the Customer in writing and apply to all fixtures which FPL has installed on the Customer's behalf. Selection changes may be made by the Customer at any time and will become effective ninety (90) days after written notice is received.

Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

SPECIAL CONDITIONS:

Customers whose lights are turned off during sea turtle nesting season will receive a credit equal to the fuel charges associated with the fixtures that are turned off.

TERM OF SERVICE:

Initial term of ten (10) years with automatic, successive five (5) year extensions unless terminated in writing by either FPL or the Customer at least ninety (90) days prior to the current term's expiration.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

160001 Hearing Exhibits 00302

STREET LIGHTING METERED SERVICE

RATE SCHEDULE: SL-1M

AVAILABLE:

In all territory served.

APPLICATION:

For customer-owned lighting of streets and roadways, whether public or private, which are thoroughfares for normal flow of vehicular traffic. Lighting for other applications such as: municipally and privately-owned parking lots; parks and recreational areas; or any other area not expressly defined above, is not permitted under this schedule.

SERVICE:

Single phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$13.00
Non-Fuel Energy Charges:	
Base Energy Charge	2.795 ¢ per kWh
Conservation Charge	See Sheet No. 8.030
Capacity Payment Charge	See Sheet No. 8.030
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum:	$13.00

TERM OF SERVICE:

Not less than one (1) year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

PREMIUM LIGHTING

RATE SCHEDULE: PL-1

AVAILABLE:

In all territory served.

APPLICATION:

FPL-owned lighting facilities not available under rate schedule SL-1 and OL-1. To any Customer for the sole purpose of lighting streets, roadways and common areas, other than individual residential locations. This includes but is not limited to parking lots, homeowners association common areas, or parks.

SERVICE:

Service will be unmetered and will include lighting installation, lamp replacement and facilities maintenance for FPL-owned lighting systems. It will also include energy from dusk each day until dawn the following day.

The Company, while exercising reasonable diligence at all times to furnish service hereunder, does not guarantee continuous lighting and will not be liable for damages for any interruption, deficiency or failure of service, and reserves the right to interrupt service at any time for necessary repairs to lines or equipment.

LIMITATION OF SERVICE:

Installation shall be made only when, in the judgement of the Company, the location and the type of the facilities are, and will continue to be, easily and economically accessible to the Company equipment and personnel for both construction and maintenance.

Stand-by, non-firm, or resale service is not permitted hereunder.

TERM OF SERVICE:

The term of service is (20) twenty years. At the end of the term of service, the Customer may elect to execute a new agreement based on the current estimated replacement costs. The Company will retain ownership of these facilities.

FACILITIES PAYMENT OPTION:

The Customer will pay for the facilities in a lump sum in advance of construction. The amount will be the Company's total work order cost for these facilities times the Present Value Revenue Requirement (PVRR) multiplier of ~~1.1941.~~1.1942. Monthly Maintenance and Energy charges will apply for the term of service.

FACILITIES SELECTION:

Facilities selection shall be made by the Customer in writing by executing the Company's Premium Lighting Agreement.

(Continued on Sheet No. 8.721)

160001 Hearing Exhibits 00304

(Continued from Sheet No. 8.720)

MONTHLY RATE :

Facilities:

Paid in full:	Monthly rate is zero, for Customer's who have executed a Premium Lighting Agreement before March 1, 2010:
10 years payment option:	~~1.362~~1.358% of total work order cost.
20 years payment option:	~~0.925~~0.920% of total work order cost.
Maintenance:	FPL's estimated costs of maintaining lighting facilities.
Billing:	FPL reserves the right to assess a charge for the recovery of any dedicated billing system developed solely for this rate.
Energy:	KWH Consumption for fixtures shall be estimated using the following formula:

$$KWH = \frac{\text{Unit Wattage (usage)} \times 353.3 \text{ hours per month}}{1000}$$

Non-Fuel Energy	~~2.755~~2.850 ¢/kWh
Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

During the initial installation period:
Facilities in service for 15 days or less will not be billed;
Facilities in service for 16 days or more will be billed for a full month.

MINIMUM MONTHLY BILL:

The minimum monthly bill shall be the applicable Facilities Maintenance and Billing charges.

(Continued on Sheet No. 8.722)

160001 Hearing Exhibits 00305

(Continued from Sheet No. 8.721)

EARLY TERMINATION:

If the Customer no longer wishes to receive service under this schedule, the Customer may terminate the Premium Lighting Agreement by giving at least (90) ninety days advance written notice to the Company. Upon early termination of service, the Customer shall pay an amount computed by applying the following Termination Factors to the installed cost of the facilities, based on the year in which the Agreement was terminated. These Termination Factors will not apply to Customers who elected to pay for the facilities in a lump sum in lieu of a monthly payment.

FPL may also charge the Customer for the cost to the utility for removing the facilities.

Ten (10) Years Payment Option	Termination Factor
1	~~1.1941~~1.1942
2	~~1.0306~~1.0312
3	~~0.9473~~0.9475
4	0.8575
5	~~0.7608~~0.7605
6	~~0.6565~~0.6560
7	~~0.5441~~0.5435
8	~~0.4230~~0.4224
9	~~0.2924~~0.2919
10	~~0.1517~~0.1513
>10	0.0000

Twenty (20) Years Payment Option	Termination Factor
1	~~1.1941~~1.1942
2	~~1.0831~~1.0838
3	~~1.0563~~1.0568
4	~~1.0275~~1.0277
5	~~0.9965~~0.9964
6	~~0.9630~~0.9627
7	~~0.9269~~0.9264
8	~~0.8880~~0.8873
9	~~0.8461~~0.8452
10	~~0.8009~~0.7999
11	~~0.7523~~0.7510
12	~~0.6998~~0.6984
13	~~0.6432~~0.6418
14	~~0.5823~~0.5808
15	~~0.5166~~0.5151
16	~~0.4458~~0.4443
17	~~0.3695~~0.3681
18	~~0.2872~~0.2861
19	~~0.1985~~0.1977
20	~~0.1030~~0.1025
>20	0.0000

WILLFUL DAMAGE:

In the event of willful damage to these facilities, FPL will provide the initial repair of each installed item at its expense. Upon the second occurrence of willful damage, and subsequent occurrence to these FPL-owned facilities, the Customer will be responsible for the cost for repair or replacement.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

OUTDOOR LIGHTING

RATE SCHEDULE OL-1

AVAILABLE:

In all territory served.

APPLICATION:

For year-round outdoor security lighting of yards, walkways and other areas. Lights to be served hereunder shall be at locations which are easily and economically accessible to Company ~~equipment~~vehicles and personnel for construction and maintenance.

It is intended that Company-owned security lights will be installed on existing Company-owned electric facilities, or short extension thereto, in areas where a street lighting system is not provided or is not sufficient to cover the security lighting needs of a particular individual or location. Where more extensive security lighting is required, such as for large parking lots or other commercial areas, the Customer will provide the fixtures, supports and connecting wiring; the Company will connect to the Customer's system and provide the services indicated below.

SERVICE:

Service includes lamp renewals, energy from approximately dusk each day until approximately dawn the following day, and maintenance of Company-owned facilities. The Company will replace all burned-out lamps and will maintain its facilities during regular daytime working hours as soon as practicable following notification by the Customer that such work is necessary. The Company shall be permitted to enter the Customer's premises at all reasonable times for the purpose of inspecting, maintaining, installing and removing any or all of its equipment and facilities.

The Company, while exercising reasonable diligence at all times to furnish service hereunder, does not guarantee continuous lighting and will not be liable for damages for any interruption, deficiency or failure of service, and reserves the right to interrupt service at any time for necessary repairs to lines or equipment.

LIMITATION OF SERVICE:

This schedule is not available for service normally supplied on the Company's standard street lighting schedules. Company-owned facilities will be installed only on Company-owned poles. Customer-owned facilities will be installed only on Customer-owned poles. Overhead conductors will not be installed in any area designated as an underground distribution area, or any area, premises or location served from an underground source. Customer must have an active house or premise account associated with this service. Stand-by or resale service not permitted hereunder.

MONTHLY RATE:

Luminaire Type		Lamp Size Initial Lumens/Watts		KWH/Mo. Estimate	Charge for Company-Owned Unit ($) Fixtures	Maintenance	Energy Non-Fuel **	Total	Charge for Customer-Owned Unit ($) Relamping/ Energy	Energy Only
High Pressure Sodium Vapor		6,300	70	29	$5.05	$~~1.85~~1.90	$~~0.81~~0.84	$~~0.81~~0.84	~~7.71~~7.79	$~~2.66~~2.69
"	"	9,500	100	41	$5.16	$~~1.85~~1.90	$~~1.14~~1.19	$~~1.14~~1.19	~~8.15~~8.25	$~~2.99~~3.04
"	"	16,000	150	60	$5.34	$~~1.88~~1.93	$~~1.67~~1.74	$~~1.67~~1.74	~~8.89~~9.01	$~~3.55~~3.62
"	"	22,000	200	88	$7.77	$~~2.43~~2.49	$~~2.45~~2.55	$~~2.45~~2.55	~~12.65~~12.81	$~~4.88~~4.98
"	"	50,000	400	168	$8.27	$~~2.39~~2.45	$~~4.67~~4.88	$~~4.67~~4.88	~~15.33~~15.60	$~~7.06~~7.27
"	" *	12,000	150	60	$~~5.74~~5.34	$~~2.15~~1.93	$~~1.67~~1.74	$~~1.67~~1.74	~~9.56~~9.01	$~~3.82~~3.89
Mercury Vapor	*	6,000	140	62	$3.88	$~~1.66~~1.70	$~~1.72~~1.80	$~~1.72~~1.80	~~7.26~~7.38	$~~3.38~~3.46

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective: ~~April~~January 1, ~~2016~~2017

"	"	*	8,600	175	77	$3.90	$~~1.66~~1.70	$~~2.14~~2.23	~~7.70~~7.83	$~~3.80~~3.89
$~~2.14~~2.23										
"	"	*	21,500	400	160	$6.39	$~~2.34~~2.40	$~~4.45~~4.64	~~13.18~~13.43	$~~6.79~~6.98
$~~4.45~~4.64										

* These units are closed to new Company installations.

** The non-fuel energy charge is ~~-2.780~~2.902¢ per kWh.

(Continued on Sheet No. 8.726)

160001 Hearing Exhibits 00308

(Continued from Sheet No. 8.725)

Charges for other Company-owned facilities:

Wood pole and span of conductors:	$~~9.69~~11.14
Concrete pole and span of conductors:	$~~13.08~~15.03
Fiberglass pole and span of conductors:	$~~15.38~~17.68
Steel pole used only for the street lighting system *	$~~13.08~~15.03
Underground conductors (excluding trenching)	$~~0.078~~0.085 per foot
Down-guy, Anchor and Protector	$~~9.34~~10.13

For Customer-owned outdoor lights, where the Customer contracts to relamp at no cost to FPL, the monthly rate for non-fuel energy shall be $~~9.34~~ 2.902¢ per kWh of estimated usage of each unit plus adjustments.

Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Clause	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

TERM OF SERVICE:

Not less than one year. In the event the Company installs any facilities for which there is an added monthly charge, the Term of Service shall be for not less than three years.

If the Customer terminates service before the expiration of the initial term of the agreement, the Company may require reimbursement for the total expenditures made to provide such service, plus the cost of removal of the facilities installed less the salvage value thereof, and less credit for all monthly payments made for Company-owned facilities.

WILLFUL DAMAGE:

In the event of willful damage to these facilities, FPL will provide the initial repair of each installed item at its expense. Upon the second occurrence of willful damage, and subsequent occurrence to these FPL-owned facilities, the Customer will be responsible for the cost for repair or replacement.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

COMPANY-OWNED FACILITIES:

Company-owned luminaires normally will be mounted on Company's existing distribution poles and served from existing overhead wires. The Company will provide one span of secondary conductor from existing secondary facilities to a Company-owned light at the Company's expense. When requested by the Customer, and at the option of the Company, additional spans of wire or additional poles or underground conductors may be installed by the Company upon agreement by the Customer to use the facilities for a minimum of three years and pay each month the charges specified under MONTHLY RATE.

MONTHLY RATE

The Customer will make a lump sum payment for the cost of changes in the height of existing poles or the installation of additional poles in the Company's distribution lines or the cost of any other facilities required for the installation of lights to be served hereunder.

~~At the Customer's request, the Company will upgrade to a higher level of illumination without a service charge when the changes are consistent with good engineering practices. The Customer will pay the Company the net costs incurred in making other lamp size changes. In all cases where luminaires are replaced, the Customer will sign a new service agreement. Billing on the rate for the new~~

~~luminaire or lamp size will begin as of the next regular billing date. A luminaire may be relocated at the Customer's request upon payment by the Customer of the costs of removal and reinstallation.~~

~~The Company will not be required to install equipment at any location where the service may be objectionable to others. If it is found after installation that the light is objectionable, the Company may terminate the service.~~

(Continued on Sheet No. 8.727)

(Continued from Sheet No. 8.726)

At the Customer request, the Company will upgrade to a higher level of illumination without a service charge when the changes are consistent with good engineering practices. The Customer will pay the Company the net costs incurred in making other lamp size changes. In all cases where luminaries are replaced, the Customer will sign a new service agreement. Billing on the rate for the new luminaire or lamp size will begin as of the next regular billing date. A luminaire may be relocated at the Customer's request upon payment by the Customer of the costs of removal and reinstallation.

The Company will not be required to install equipment at any location where the service may be objectionable to others. If it is found after installation that the light is objectionable, the Company may terminate the service.

When the Company relocates or removes its facilities to comply with governmental requirements, or for any other reason, either the Company or the Customer shall have the right, upon written notice, to discontinue service hereunder without obligation or liability.

SPECIAL CONDITIONS:

Customers whose lights are turned off during sea turtle nesting season will receive a credit equal to the fuel charges associated with the fixtures that are turned off.

CUSTOMER-OWNED FACILITIES:

Customer-owned luminaires and other facilities will be of a type and design specified by the Company to permit servicing and lamp replacement at no abnormal cost. The Customer will provide all poles, fixtures, initial lamps and controls, and circuits up to the point of connection to the Company's supply lines, and an adequate support for the Company-owned service conductors.

The Company will provide an overhead service drop from its existing secondary conductors to the point of service designated by the Company for Customer-owned lights. Underground service conductors will be installed in lieu of the overhead conductors at the Customer's request, and upon payment by the Customer of the installed cost of the underground conductors after allowance for the cost of equivalent overhead service conductors and any trenching and backfilling provided by the Customer.

DEFINITIONS:

A "Luminaire," as defined by the Illuminating Engineering Society, is a complete lighting unit consisting of a lamp (bulb), together with parts designed to distribute the light, to position and protect the lamp, and connect the lamp to the power supply.

A "Conventional" luminaire is supported by a bracket that is mounted on the side of an ordinary wood pole or an ornamental pole. This is the only type of luminaire offered where service is to be supplied from overhead conductors, although this luminaire may also be used when service is supplied from underground conductors.

A "Contemporary" luminaire is of modern design and is mounted on top of an ornamental pole. Underground conductors are required.

A "Traditional" luminaire resembles an Early American carriage lantern and is mounted on top of a pole. It requires an ornamental pole and underground conductors to a source of supply.

An "Ornamental" pole is one made of concrete or fiberglass.

160001 Hearing Exhibits 00311

TRAFFIC SIGNAL SERVICE

RATE SCHEDULE: SL-2

AVAILABLE:

In all territory served.

APPLICATION:

Service for traffic signal lighting where the signal system and the circuit to connect with Company's existing supply lines are installed, owned and maintained by Customer~~.~~ and were active prior to January 1, 2017.

SERVICE:

Single phase, 60 hertz and approximately 120/240 volts or higher, at Company's option.

MONTHLY RATE:

Non-Fuel Energy Charges:

Base Energy Charge	~~4.507~~4.731 ¢ per kWh
Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1

Additional Charges:

Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: $3.24 at each point of delivery.

Note: During the initial installation period of facilities:
Lights and facilities in service for 15 days or less will not be billed;
Lights and facilities in service for 16 days or more will be billed for a full month.

CALCULATED USAGE:

The Calculated Usage at each point of delivery shall be determined by operating tests or utilization of manufacturers' ratings and specifications. The monthly operation shall be based on a standard of 730 hours; however, that portion of the operation which is on a noncontinuous basis shall be adjusted to reflect such operation.

TERM OF SERVICE:

Not less than one (1) billing period.

NOTICE OF CHANGES:

The Customer shall notify the Company at least 30 days prior to any change in rating of the equipment served or the period of operation.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

TRAFFIC SIGNAL METERED SERVICE

RATE SCHEDULE: SL-2M

AVAILABLE:

In all territory served.

APPLICATION:

Service for traffic signal lighting where the signal system and the circuit to connect with Company's existing supply lines are installed, owned and maintained by Customer.

SERVICE:

Single phase, 60 hertz and approximately 120/240 volts or higher, at Company's option.

MONTHLY RATE:

Customer Charge:	$6.00
Non-Fuel Energy Charges:	
Base Energy Charge	4.596 ¢ per kWh
Conservation Charge	See Sheet No. 8.030
Capacity Payment Charge	See Sheet No. 8.030
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum:	$6.00

TERM OF SERVICE:

Not less than one (1) year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

RECREATIONAL LIGHTING

(Closed Schedule)

RATE SCHEDULE: RL-1

AVAILABLE:

In all territory served. Available to any customer, who, as of January 16, 2001, was either taking service pursuant to this schedule or had a fully executed Recreational Lighting Agreement with the Company.

APPLICATION:

For FPL-owned facilities for the purpose of lighting community recreational areas. This includes, but is not limitied to, baseball, softball, football, soccer, tennis, and basketball.

SERVICE:

Service will be metered and will include lighting installation, lamp replacement and facilities maintenance for FPL-owned lighting systems.

The Company, while exercising reasonable diligence at all times to furnish service hereunder, does not guarantee continuous lighting and will not be liable for damages for any interruption, deficiency or failure of service, and reserves the right to interrupt service at any time for necessary repairs to lines or equipment.

LIMITATION OF SERVICE:

Installation shall be made only when, in the judgement of the Company, the location and the type of the facilities are, and will continue to be, easily and economically accessible to the Company equipment and personnel for both construction and maintenance.

Stand-by, non-firm, or resale service is not permitted hereunder.

TERM OF SERVICE:

The term of service is (20) twenty years. At the end of the term of service, the Customer may elect to execute a new Agreement based on the current estimated replacement costs. The Company will retain ownership of these facilities.

FACILITIES PAYMENT OPTION:

The Customer will pay for the facilities in a lump sum in advance of construction. The amount will be the Company's total work order cost for these facilities times the Present Value Revenue Requirement (PVRR) multiplier of ~~.~~1.1942. Monthly Maintenance and energy charges will apply for the term of service.

FACILITIES SELECTION:

Facilities selection shall be made by the Customer in writing by executing the Company's Recreational Lighting Agreement.

(Continued on Sheet No. 8.744)

160001 Hearing Exhibits 00314

(Continued from Sheet No. 8.743)

MONTHLY RATE :

Facilities:

Paid in full:	Monthly rate is zero.
10 years payment option:	1.358% of total work order cost.*
20 years payment option:	0.920% of total work order cost.*

* Both (10) ten and (20) twenty year payment options are closed to new service, and are only available for the duration of the term of service of those customers that have fully executed a Recreational Lighting Agreement with the Company before January 16, 2001.

Maintenance:	FPL's estimated costs of maintaining lighting facilities.
Billing:	FPL reserves the right to assess a charge for the recovery of any dedicated billing system developed solely for this rate.
Charge Per Month:	Company's otherwise applicable general service rate schedule.
Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

MINIMUM MONTHLY BILL:

As provided in the otherwise applicable rate schedule, plus the Facilities Maintenance and Billing charges.

(Continued on Sheet No. 8.745)

160001 Hearing Exhibits 00315

(Continued from Sheet No. 8.744)

EARLY TERMINATION:

If the Customer no longer wishes to receive service under this schedule, the Customer may terminate the Recreational Lighting Agreement by giving at least (90) ninety days advance written notice to the Company. Upon early termination of service, the Customer shall pay an amount computed by applying the following Termination Factors to the installed cost of the facilities, based on the year in which the Agreement was terminated. These Termination Factors will not apply to Customers who elected to pay for the facilities in a lump sum in lieu of a monthly payment.

FPL may also charge the Customer for the cost to the utility for removing the facilities.

Ten (10) Years Payment Option	Termination Factor	Twenty (20) Years Payment Option	Termination Factor
1	~~1.1941~~1.1942	1	~~1.1941~~1.1942
2	~~1.0306~~1.0312	2	~~1.0831~~1.0838
3	~~0.9473~~0.9475	3	~~1.0563~~1.0568
4	~~0.8575~~0.8575	4	~~1.0275~~1.0277
5	~~0.7608~~0.7605	5	~~0.9965~~0.9964
6	~~0.6565~~0.6560	6	~~0.9630~~0.9627
7	~~0.5441~~0.5435	7	~~0.9269~~0.9264
8	~~0.4230~~0.4224	8	~~0.8880~~0.8873
9	~~0.2924~~0.2919	9	~~0.8461~~0.8452
10	~~0.1517~~0.1513	10	~~0.8009~~0.7999
>10	0.0000	11	~~0.7523~~0.7510
		12	~~0.6998~~0.6984
		13	~~0.6432~~0.6418
		14	~~0.5823~~0.5808
		15	~~0.5166~~0.5151
		16	~~0.4458~~0.4443
		17	~~0.3695~~0.3681
		18	~~0.2872~~0.2861
		19	~~0.1985~~0.1977
		20	~~0.1030~~0.1025
		>20	0.0000

WILLFUL DAMAGE:

In the event of willful damage to these facilities, FPL will provide the initial repair of each installed item at its expense. Upon the second occurrence of willful damage, and subsequent occurrence to these FPL-owned facilities, the Customer will be responsible for the cost for repair or replacement.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective: January ~~2, 2013~~1, 2017

STANDBY AND SUPPLEMENTAL SERVICE

RATE SCHEDULE: SST-1

AVAILABLE:

In all territory served by the Company. Service under this rate schedule is on a customer by customer basis subject to the completion of arrangements necessary for implementation.

APPLICATION:

For electric service to any Customer, at a point of delivery, whose electric service requirements for the Customer's load are supplied or supplemented from the Customer's generation equipment at that point of service and require standby and/or supplemental service. For purposes of determining applicability of this rate schedule, the following definitions shall be used:

(1) "Standby Service" means electric energy or capacity supplied by the Company to replace energy or capacity ordinarily generated by the Customer's own generation equipment during periods of either scheduled (maintenance) or unscheduled (backup) outages of all or a portion of the Customer's generation.

(2) "Supplemental Service" means electric energy or capacity supplied by the Company in addition to that which is normally provided by the Customer's own generation equipment.

A Customer is required to take service under this rate schedule if the Customer's total generation capacity is more than 20% of the Customer's total electrical load and the Customer's generators are not for emergency purposes only.

Customers taking service under this rate schedule shall enter into a Standby and Supplemental Service Agreement ("Agreement"); however, failure to execute such an agreement will not pre-empt the application of this rate schedule for service.

SERVICE:

Three phase, 60 hertz, and at the available standard voltage. All service supplied by the Company shall be furnished through one metering point. Resale of service is not permitted hereunder.

Transformation Rider - TR, Sheet No. 8.820, does not apply to Standby Service.

MONTHLY RATE:

STANDBY SERVICE

Delivery Voltage:	Below 69 kV			69kV & Above
Contract Standby Demand:	SST-1(D1) Below 500 kW	SST-1(D2) 500 to 1,999 kW	SST-1(D3) 2,000 kW & Above	SST-1(T) All Levels
Customer Charge:	$~~112.42~~	~~$112.42~~	~~$421.57~~125.00	$125.00
~~$425.00~~ ~~$1,631.99~~1,800.00				
Demand Charges:				
Base Demand Charges:				
Distribution Demand Charge per kW of Contract Standby Demand	$~~3.03~~3.00	$~~3.03~~3.00	$~~3.03~~3.00	N/A
Reservation Demand Charge per kW	$~~1.17~~1.48	$~~1.17~~1.48	$~~1.17~~1.48	$~~1.22~~1.33
Daily Demand Charge per kW for each daily maximum On-Peak Standby Demand	$~~0.57~~0.70	$~~0.57~~0.70	$~~0.57~~0.70	$~~0.34~~0.44
Capacity Payment and Conservation Charges	See Sheet No. 8.030.1			

(Continued on Sheet No. 8.751)

160001 Hearing Exhibits 00317

(Continued from Sheet No. 8.750)

Delivery Voltage:	Below 69 kV			69 kV & Above
	SST-1(D1)	SST-1(D2)	SST-1(D3)	SST-1(T)
Contract Standby Demand:	Below 500 kW	500 to 1,999 kW	2,000 kW & Above	All Levels
Non-Fuel Energy Charges:				
Base Energy Charges:				
On-Peak Period charge per kWh	~~0.984~~0.707 ¢	~~0.984~~0.707 ¢	~~0.984~~0.707 ¢	~~0.957~~0.707 ¢
Off-Peak Period charge per kWh	~~0.984~~0.707 ¢	~~0.984~~0.707 ¢	~~0.984~~0.707 ¢	~~0.957~~0.707 ¢

Environmental Charge — See Sheet No. 8.030.1

Additional Charges:

Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the Base Demand Charges.

DEMAND CALCULATION:

The Demand Charge for Standby Service shall be (1) the charge for Distribution Demand **plus** (2) the greater of the sum of the Daily Demand Charges **or** the Reservation Demand Charge times the maximum On-Peak Standby Demand actually registered during the month **plus** (3) the Reservation Demand Charge times the difference between the Contract Standby Demand and the maximum On-Peak Standby Demand actually registered during the month.

SUPPLEMENTAL SERVICE

Supplemental Service shall be the total power supplied by the Company minus the Standby Service supplied by the Company during the same metering period. The charge for all Supplemental Service shall be calculated by applying the applicable retail rate schedule, excluding the customer charge.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

CONTRACT STANDBY DEMAND:

The level of Customer's generation requiring Standby Service as specified in the Agreement. This Contract Standby Demand will not be less than the maximum load actually served by the Customer's generation during the current month or prior 23-month period less the amount specified as the Customer's load which would not have to be served by the Company in the event of an outage of the Customer's generation equipment. For a Customer receiving only Standby Service as identified under Special Provisions, the Contract Standby Demand shall be maximum load actually served by the Company during the current month or prior 23-month period.

A Customer's Contract Standby Demand may be re-established to allow for the following adjustments:

1. Demand reduction resulting from the installation of FPL Demand Side Management Measures or FPL Research Project efficiency measures; or

(Continued on Sheet No. 8.752)

160001 Hearing Exhibits 00318

INTERRUPTIBLE STANDBY AND SUPPLEMENTAL SERVICE
(OPTIONAL)

RATE SCHEDULE: ISST-1

AVAILABLE:

In all territory served by the Company. Service under this rate schedule is on a customer by customer basis subject to the completion of arrangements necessary for implementation.

LIMITATION OF AVAILABILITY:

This schedule may be modified or withdrawn subject to determinations made under Commission Rule 25-6.0438, F.A.C., Non-Firm Electric Service - Terms and Conditions or any other Commission determination.

APPLICATION:

A Customer who is eligible to receive service under the Standby and Supplemental Service (SST-1) rate schedule may, as an option, take service under this rate schedule, unless the Customer has entered into a contract to sell firm capacity and/or energy to the Company, and the Customer cannot restart its generation equipment without power supplied by the Company, in which case the Customer may only receive Standby and Supplemental Service under the Company's SST-1 rate schedule.

Customers taking service under this rate schedule shall enter into an Interruptible Standby and Supplemental Service Agreement ("Agreement"). This interruptible load shall not be served on a firm service basis until service has been terminated under this rate schedule.

SERVICE:

Three phase, 60 hertz, and at the available standard voltage.

A designated portion of the Customer's load served under this schedule is subject to interruption by the Company. Transformation Rider-TR, where applicable, shall only apply to the Customer's Contract Standby Demand for delivery voltage below 69 kV. Resale of service is not permitted hereunder.

MONTHLY RATE:

STANDBY SERVICE Delivery Voltage:		Distribution Below 69 kV ISST-1(D)	Transmission 69 kV & Above ISST-1(T)
Customer Charge:		$~~421.57~~425.00	$~~2,125.83~~1,800.00
Demand Charges:			
Base Demand Charges:			
Distribution Demand Charge per kW of Contract Standby Demand		$3.033.00	N/A
Reservation Demand Charge per kW of Interruptible Standby Demand		$~~0.16~~0.25	$~~0.24~~0.30
Reservation Demand Charge per kW of Firm Standby Demand		$~~1.171~~.48	$~~0.971~~.33
Daily Demand Charge per kW for each daily maximum On-Peak Interruptible Standby Demand		$~~0.07~~0.70	$~~0.09~~0.44
Daily Demand Charge per kW for each daily maximum On-Peak Firm Standby Demand		$~~0.57~~0.12	
	$~~0.45~~0.12 Capacity Payment and Conservation Charges See Sheet No. 8.030.1		
Non-Fuel Energy Charges:			
Base Energy Charges:			
On-Peak Period charge per kWh		0.984~~0~~.707 ¢	0.900~~0~~.707¢
Off-Peak Period charge per kWh		~~0.984~~0.707 ¢	0.900~~0~~.707¢
Environmental Charge	See Sheet No. 8.030.1		

(Continued on Sheet No. 8.761)

160001 Hearing Exhibits 00319

TRANSFORMATION RIDER - TR

AVAILABLE:

In all territory served.

APPLICATION:

In conjunction with any commercial or industrial rate schedule specifying delivery of service at any available standard voltage when Customer takes service from available primary lines of 2400 volts or higher at a single point of delivery.

MONTHLY CREDIT:

The Company, at its option, will either provide and maintain transformation facilities equivalent to the capacity that would be provided if the load were served at a secondary voltage from transformers at one location or, when Customer furnishes transformers, the Company will allow a monthly credit of $~~0.30~~0.15 per kW of Billing Demand. Any transformer capacity required by the Customer in excess of that provided by the Company hereunder may be rented by the Customer at the Company's standard rental charge.

The credit will be deducted from the monthly bill as computed in accordance with the provisions of the Monthly Rate section of the applicable Rate Schedule before application of any discounts or adjustments. No monthly bill will be rendered for an amount less than the minimum monthly bill called for by the Agreement for Service.

SPECIAL CONDITIONS:

The Company may change its primary voltage at any time after reasonable advance notice to any Customer receiving credit hereunder and affected by such change, and the Customer then has the option of changing its system so as to receive service at the new line voltage or of accepting service (without the benefit of this rider) through transformers supplied by the Company.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

SEASONAL DEMAND – TIME OF USE RIDER – SDTR
(OPTIONAL)

RIDER: SDTR

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW. This is an optional rate available to customers otherwise served under the GSD-1 GSDT-1, GSLD-1, GSLDT-1, GSLD-2 or GSLDT-2 Rate Schedules.

SERVICE:
Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:
OPTION A: Non-Seasonal Standard Rate

Annual Maximum Demand	SDTR-1 21-499 kW	SDTR-2 500-1,999 kW	SDTR-3 2,000 kW or greater
Customer Charge: $~~219.22~~225.00	$~~26.97~~25.00	$~~61.83~~75.00	
Demand Charges:			
Seasonal On-peak Demand Charge Per kW of Seasonal On-peak Demand	$~~9.60~~10.10	$~~10.47~~11.40	$~~10.81~~12.00
Non-Seasonal Demand Charge $~~9.57~~11.18 Per kW of Non- Seasonal Maximum Demand	~~$7.92~~	~~$9.12~~8.90	$10.80
Capacity Payment Charge:	See Sheet No. 8.030		
Conservation Charge:	See Sheet No. 8.030		
Energy Charges:			
Base Seasonal On-Peak Per kWh of Seasonal On-Peak Energy	~~7.278~~8.093 ¢	~~5.040~~5.648 ¢	~~4.302~~4.538 ¢
Base Seasonal Off-Peak Per kWh of Seasonal Off-Peak Energy	~~1.371~~1.459 ¢	~~1.035~~1.143 ¢	~~0.931~~1.112 ¢
Base Non-Seasonal Energy Charge Per kWh of Non-Seasonal Energy	~~1.934~~2.035 ¢ ~~1.287~~1.427 ¢	~~1.430~~1.585 ¢	
Environmental Charge:	See Sheet No. 8.030		
Additional Charges:			
Fuel Charge:	See Sheet No. 8.030		
Storm Charge:	See Sheet No. 8.040		
Franchise Fee:	See Sheet No. 8.031		
Tax Clause:	See Sheet No. 8.031		

(Continued from Sheet No. 8.830)

OPTION B: Non-Seasonal Time of Use Rate

Annual Maximum Demand	SDTR-1 21-499 kW	SDTR-2 500-1,999 kW	SDTR-3 2,000 kW or greater
Customer Charge: $~~219.22~~225.00	$~~26.97~~25.00	$~~61.83~~75.00	
Demand Charges:			
Seasonal On-peak Demand Charge $~~10.81~~12.00 Per kW of Seasonal On-peak Demand	$~~9.60~~10.10	$~~10.47~~11.40	
Non-Seasonal Demand Charge Per kW of Non- Seasonal Peak Demand	$~~7.92~~8.90	$~~9.12~~10.80	$~~9.57~~11.18
Capacity Payment Charge	See Sheet No. 8.030		
Conservation Charge	See Sheet No. 8.030		
Energy Charges:			
Base Seasonal On-Peak ~~4.302~~4.538 ¢ Per kWh of Seasonal On-Peak Energy	~~7.278~~8.093 ¢	~~5.040~~5.648 ¢	
Base Seasonal Off-Peak ~~0.931~~1.112 ¢ Per kWh of Seasonal Off-Peak Energy	~~1.371~~1.459 ¢	~~1.035~~1.143 ¢	
Base Non-Seasonal On-Peak ~~2.479~~3.113 ¢ Per kWh of Non-Seasonal On-Peak Energy	~~3.881~~4.622 ¢	~~2.710~~3.384 ¢	
Base Non-Seasonal Off-Peak ~~0.931~~1.112 ¢ Per kWh of Non-Seasonal Off-Peak Energy	~~1.371~~1.459 ¢	~~1.035~~1.143 ¢	
Environmental Charge	See Sheet No. 8.030		
Additional Charges:			
Fuel Charge	See Sheet No. 8.030		
Storm Charge	See Sheet No. 8.040		
Franchise Fee	See Sheet No. 8.031		
Tax Clause	See Sheet No. 8.031		

Minimum Charge: The Customer Charge plus the currently effective Demand Charges.

NON-SEASONAL RATING PERIODS (OPTION B only):

Non-Seasonal On-Peak Period:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through May 31 and October 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day.

Non-Seasonal Off-Peak Period: All other hours.

(Continued On Sheet No. 8.832)

160001 Hearing Exhibits 00322

SURETY BOND

KNOW ALL PERSONS BY THESE PRESENTS:

THAT WE,_____ as Principal at (mailing address)_____,

and_____, a surety company at (mailing address) _____ authorized to do business in the State of Florida, as Surety are held and firmly bound to Florida Power & Light Company, a corporation organized and existing under the laws of the State of Florida, its successors and assigns, in the amount of $, lawful money of the United States of America for the payment of which the Principal and Surety, their heirs, executors, administrators, successors and assigns are hereby jointly and severally bound.

WHEREAS, pursuant to its authorized General Rules and Regulations for Electric Service, Florida Power & Light Company requires the Principal to establish credit for prompt payment of its monthly utility bills, and Principal and Florida Power & Light Company agree that Principal may do so by furnishing this surety bond for prompt payment of the monthly utility bills to be rendered by Florida Power & Light Company;

NOW THEREFORE, the condition of this obligation is such that if the Principal shall promptly pay all amounts which may be due by Principal to Florida Power & Light Company for utility services in the Principal's name at any or all premises, then this obligation shall be null and void; otherwise it shall remain in full force and effect.

PROVIDED FURTHER, that Principal and Surety jointly and severally agree that if at any time Principal's payment, or any part thereof, of Principal's obligations to Florida Power & Light Company is rescinded or must otherwise be restored or returned for any reason whatsoever (Including, but not limited to, insolvency, bankruptcy or reorganization), then the Surety obligation shall, to the extent of the payment rescinded or returned, be deemed to have continued in existence, notwithstanding such previous payment, and the Surety obligation shall continue to be effective or be reinstated, as the case may be, as to such payment, all as though such previous payment had never been made;

PROVIDED FURTHER, that regardless of the number of years this bond shall continue or be continued in force and of the number of premiums which shall be payable or paid, the Surety shall not be liable thereunder for a larger amount, in the aggregate, than the amount of this bond, unless suit must be brought for enforcement of the within obligations in which case the Surety will also be liable for all costs in connection therewith and reasonable attorneys' fees, including costs of and fees for appeals; and

PROVIDED FURTHER, that should the Surety so elect, this bond may be canceled by the Surety as to subsequent liability by giving thirty (30) days notice in writing by certified mail-return receipt requested to Florida Power & Light Company at P.O. Box 025209, Miami, Florida 33102-5209. The notice of cancellation shall not be effective unless it includes the Principal's name and "Master Account Number_____" written thereon.

Signed, sealed and dated this_____ day of_____.

[ ]

Signature format in this section will vary depending on type of legal entity
(Corporation, Partnership, Joint Venture, Sole Proprietor)

[ ]

Corporate	Surety_____	Notary
Seal	By_____	Seal
	(Designated in attached Power of Attorney, If not Florida Resident, countersigned below.)	
of SURETY		(Surety)

(Continued on Sheet No. 9.441)

CONTRACT PROVISIONS - VARIOUS

FACILITIES RENTAL SERVICE. When required by the Customer, the Company may, at its option, provide and maintain transformers and other facilities which are required by the Customer beyond the Point of Delivery or which are needed because the Customer requires unusual facilities due to the nature of his equipment. The Company shall not be required to install facilities if they cannot be economically justified. The charge for this service is based on the agreed installed cost of such facilities.

Upon mutual agreement between the Company and the Customer, the Customer may elect to make either a lump sum payment or pay a monthly charge. The monthly charge shall recover ~~23~~21% per year of the agreed installed cost of such facilities. Those Customers electing to make a lump sum payment shall have the option of either including the cost of maintenance in a lump sum, or paying a separate monthly maintenance charge. If the Customer elects to pay for the maintenance in the lump sum, the amount will be based on the estimated cost of maintenance over the term of the contract.

Those customers renting electric facilities from the Company, subsequent to a change in the Facilities Rental Service charge and upon mutual agreement, may continue to receive electrical service under one of the following options: 1) continue the rental facilities by payment based on the revised charge, 2) purchase such facilities from the Company as mutually agreed upon, 3) purchase or lease the facilities from another source, or 4) redesign its operation to receive standard electric service from the Company.

MUNICIPAL FIRE PUMP DEMANDS. Demands caused by the operation of municipal fire pumps are waived whenever the pumps are used in emergencies for the purpose of extinguishing fires, or when the pumps are operated for testing purposes provided the time of the test is mutually agreed upon beforehand.

SECONDARY METERING ADJUSTMENT. Where the rate schedule provides for delivery of service at primary voltage and it is necessary or desirable to meter at secondary voltage, the readings of Company's meters are corrected to conform to the voltage of delivery by adding 2% to the demand indications and 3% to the kwh registrations.

UNMETERED SERVICE. In some circumstances the installation of a meter is difficult, impracticable, or not warranted by the nature of the load to be served. In such cases the Company may elect to estimate the demand and energy requirements and calculate the bill on these estimated values.

NET METERING OF CUSTOMER-OWNED RENEWABLE GENERATION. For Customers with renewable generation equipment up to a maximum of 2 MW that have executed an Interconnection Agreement for Customer-Owned Renewable Generation with the Company, the following billing parameters will apply.

The customer will be charged for electricity used in excess of the generation supplied by customer-owned renewable generation in accordance with the Company's normal billing practices. If any excess customer-owned renewable generation is delivered to the Company's electric grid during the course of a billing cycle, it will be credited to the customer's energy consumption for the next month's billing cycle.

All excess energy credits will be accumulated and be used to offset the customer's energy usage in subsequent months for a period of not more than twelve months. In the last billing cycle month of each calendar year, any unused credits for excess kWh generated will be credited to the next month's billing cycle using the average annual rate based on the Company's COG-1, As-Available Energy Tariff. In the event a customer closes the account, any of the customer's unused credits for excess kWh generated will be paid to the customer at an average annual rate based on the Company's COG-1, As-Available Energy Tariff.

Regardless of whether excess energy is delivered to the Company's electric grid, the customer will be required to pay the greater of 1. the minimum charge as stated in their applicable rate schedule, or 2. the applicable customer charge plus the applicable demand charge for the maximum measured demand during the billing period in accordance with the provisions of their applicable rate schedule. Any charges for electricity used by the customer in excess of the generation supplied by customer-owned renewable generation will be in accordance with their applicable rate schedule. The Customer's eligibility to take service under time of use rates is not affected by this provision. Additionally, the customer, at their sole discretion, may choose to take service under the Company's standby or supplemental service rate, if available.

Appendix A

Distribution Substation Facilities
Monthly Rental and Termination Factors

The Monthly Rental Factor to be applied to the in-place value of the Distribution Substation Facilities as identified in the Long-Term Rental Agreement is as follows:

	Monthly Rental Factor
Distribution Substation Facilities	~~1.67~~1.33%

Termination Fee for Initial 20 Year Period

If the Long-Term Rental Agreement for Distribution Substation Facilities is terminated by Customer during the Initial Term, Customer shall pay to Company a Termination Fee, such fee shall be computed by applying the following Termination Factors to the in-place value of the Facilities based on the year in which the Agreement is terminated:

Year Agreement Is Terminated	Termination Factors %	Year Agreement Is Terminated	Termination Factors %	Year Agreement Is Terminated	Termination Factors %
1	~~3.36~~3.33	8	~~11.16~~11.11	15	~~6.01~~6.00
2	~~6.03~~5.98	9	~~10.88~~10.83	16	4.87
3	~~8.03~~7.97	10	~~10.40~~10.36	17	3.70
4	~~9.47~~9.40	11	~~9.76~~9.73	18	~~2.48~~2.49
5	~~10.42~~10.36	12	~~8.97~~8.95	19	1.25
6	~~10.98~~10.92	13	~~8.07~~8.06	20	~~00~~.00
7	~~11.21~~11.15	14	~~7.08~~7.07		

Termination Fee for Subsequent Extension Periods

If the Long-Term Rental Agreement for Distribution Substation Facilities is terminated by Customer during an Extension, Customer shall pay to Company a Termination Fee, such fee shall be computed based on the net present value of the remaining payments under the extension period by applying the Termination Factor based on the month terminated to the monthly rental payment amount.

Month Terminated	Termination Factor	Month Terminated	Termination Factor	Month Terminated	Termination Factor	Month Terminated	Termination Factor
1	~~49.896~~49.992	16	~~39.173~~39.231	31	~~27.359~~27.386	46	~~14.342~~14.349
2	~~49.213~~49.307	17	~~38.421~~38.476	32	~~26.530~~26.555	47	~~13.429~~13.435
3	~~48.526~~48.616	18	~~37.663~~37.716	33	~~25.696~~25.719	48	~~12.509~~12.514
4	~~47.834~~47.922	19	~~36.901~~36.952	34	~~24.856~~24.878	49	~~11.584~~11.588
5	~~47.138~~47.223	20	~~36.134~~36.182	35	~~24.010~~24.031	50	~~10.652~~10.656
6	~~46.437~~46.519	21	~~35.362~~35.408	36	~~23.160~~23.178	51	~~9.715~~9.718
7	~~45.731~~45.811	22	~~34.585~~34.629	37	~~22.303~~22.321	52	~~8.772~~8.774
8	~~45.021~~45.099	23	~~33.802~~33.844	38	~~21.441~~21.457	53	~~7.822~~7.824
9	~~44.307~~44.381	24	~~33.015~~33.055	39	~~20.574~~20.589	54	~~6.866~~6.868
10	~~43.588~~43.660	25	~~32.223~~32.261	40	~~19.701~~19.714	55	~~5.904~~5.905
11	~~42.864~~42.933	26	~~31.425~~31.461	41	~~18.822~~18.834	56	~~4.936~~4.937
12	~~42.135~~42.202	27	~~30.622~~30.656	42	~~17.938~~17.949	57	3.962
13	~~41.402~~41.466	28	~~29.814~~29.847	43	~~17.047~~17.057	58	2.981
14	~~40.664~~40.726	29	~~29.001~~29.032	44	~~16.151~~16.160	59	1.994
15	~~39.921~~39.981	30	~~28.183~~28.211	45	~~15.250~~15.258	60	1.000

Issued By: S. E. Romig, Director, Rates and Tariffs
Effective: January ~~2, 2013~~1, 2017

SERVICE CHARGES

A $25.00 service charge will be made for an initial connection.

A $13.00 Reconnection Charge will be made for the reconnection of service after disconnection for nonpayment or violation of a rule or regulation.

A $12.00 service charge will be made for the connection of an existing account.

A Returned Payment Charge as allowed by Florida Statute 68.065 shall apply for each check or draft dishonored by the bank upon which it is drawn. Termination of service shall not be made for failure to pay the Returned Payment Charge.

Charges for services due and rendered which are unpaid as of the past due date are subject to a Late Payment Charge of the greater of $5.00 or 1.5% applied to any past due unpaid balance of all accounts, except the accounts of federal, state, and local governmental entities, agencies, and instrumentalities. A Late Payment Charge shall be applied to the accounts of federal, state, and local governmental entities, agencies, and instrumentalities at a rate no greater than allowed, and in a manner permitted, by applicable law.

A $49.00 Field Collection Charge will be added to a customer's bill for electric service when a field visit is made and payment is collected on a delinquent account. If service is disconnected, or a current receipt of payment is shown at the time of the field visit, this charge will not be applied.

FPL may waive the Reconnection Charge, Returned Payment Charge, Late Payment Charge and Field Collection Charge for Customers affected by natural disasters or during periods of declared emergencies or once in any twelve (12) month period for any Customer who would otherwise have had a satisfactory payment record (as defined in 25-6.097(2) F.A.C.), upon acceptance by FPL of a reasonable explanation justifying a waiver. In addition, FPL may waive the charge for connection of an existing account and the charge for an initial connection for new or existing Customers affected by natural disasters or during periods of declared emergencies.

CONSERVATION INSPECTIONS AND SERVICES

Residential Dwelling Units:
A charge of $15.00 will be made for a computerized energy analysis in which a comprehensive on-site evaluation of the residence is performed.

Commercial/Industrial:
There is no charge for conservation inspections and services (Business Energy Services).

TEMPORARY/CONSTRUCTION SERVICE

APPLICATION:

For temporary electric service to installations such as fairs, exhibitions, construction projects, displays and similar installations.

SERVICE:

Single phase or three phase, 60 hertz at the available standard secondary distribution voltage. This service is available only when the Company has existing capacity in lines, transformers and other equipment at the requested point of delivery. The Customer's service entrance electrical cable shall not exceed 200 Amp capacity.

CHARGE:

The non-refundable charge must be paid in advance of installation of such facilities which shall include service and metering equipment.

Installing and removing overhead service and meter	$367.00
Connecting and disconnecting Customer's service cable to Company's direct-buried underground facilities including installation and removal of meter	$209.00

MONTHLY RATE:

This temporary service shall be billed under the appropriate rate schedule applicable to commercial and industrial type installations.

SPECIAL CONDITIONS:

If specific electrical service other than that stated above is required, the Company, at the Customer's request, will provide such service based on the estimated cost of labor for installing and removing such additional electrical equipment. This estimated cost will be payable in advance to the Company and subject to adjustment after removal of the required facilities. All Temporary/Construction services shall be subject to all of the applicable Rules, Regulations and Tariff charges of the Company, including Service Charges.

8 METERS

8.1 Location of Meters. The Company will determine the location of and install and properly maintain at its own expense such standard meter or meters and metering equipment as may be necessary to measure the electric service used by the Customer. The Customer will keep the meter location clear of obstructions at all times in order that the meter may be read and the metering equipment may be maintained or replaced. . If a Customer requests a different location for meter placement from that designated by the Company on initial application for service and the Company agrees that the different meter location is acceptable to the Company, the Customer shall pay the incremental cost of installing the meter at the different location. If an existing Customer requests relocation of an existing installed meter and the Company agrees that the different meter location is acceptable to the Company, the existing Customer shall pay the incremental cost of relocating the meter at the different location.

8.2 Setting and Removing Meters. None but duly authorized agents of the Company or persons authorized by law shall set or remove, turn on or turn off, or make any changes which will affect the accuracy of such meters. Connections to the Company's system are to be made only by its employees.

8.3 Tampering with Meters. Title to meters and metering equipment shall be and remain in the Company. Unauthorized connections to, or tampering with the Company's meter or meters, or meter seals, or indications or evidence thereof, subjects the Customer to immediate discontinuance of service, prosecution under the laws of Florida, adjustment of prior bills for services rendered, a tampering penalty of $200 for residential and non-demand commercial customers and $1,000 for all other customers, and reimbursement to the Company for all extra expenses incurred on this account.

8.4 Meter Tests. The Company employs every practicable means to maintain the commercial accuracy of its meters. Meter tests, and billing adjustments for inaccurate meters, are in accordance with the methods and procedure prescribed by the Florida Public Service Commission.

8.5 Failure of Meter. When a meter fails, or part or all of the metering equipment is destroyed, billing will be estimated based upon the registration of check metering equipment or other available data.

9 SERVICE STANDARDS

These "General Rules and Regulations for Electric Service" include, by reference, the terms and provisions of the Company's currently effective "Electric Service Standards" on file with the Florida Public Service Commission and is available on request. The "Standards" are primarily concerned with the electrical facilities and related equipment prior to installation and use. They explain the general character of electric service supplied, the meters, and other devices furnished by the Company, and the wiring and apparatus provided and installed by the Customer. The Standards serve as a guide to architects, engineers, electrical dealers and contractors in planning, installing, repairing or renewing electrical installations.

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RATE SCHEDULE	DESCRIPTION	SHEET NO.
BA	Billing Adjustments	8.030
SC	Storm Charge	8.040
GS-1	General Service - Non Demand (0-20 kW)	8.101
GST-1	General Service - Non Demand - Time of Use (0-20 kW)	8.103
GSD-1	General Service Demand (21-499 kW)	8.105
GSDT-1	General Service Demand - Time of Use (21-499 kW)	8.107
GSL	General Service Load Management Program	8.109
NSMR	Non-Standard Meter Rider	8.120
GSCU-1	General Service Constant Usage	8.122
RS-1	Residential Service	8.201
RTR-1	Residential Time of Use Rider	8.203
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RLP	Residential Load Control Program	8.217
GSLD-1	General Service Large Demand (500-1999 kW)	8.310
GSLDT-1	General Service Large Demand - Time of Use (500-1999 kW)	8.320
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CST-1	Curtailable Service -Time of Use (500-1999 kW)	8.340
GSLD-2	General Service Large Demand (2000 kW +)	8.412
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HLFT	High Load Factor – Time of Use	8.425
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CST-3	Curtailable Service -Time of Use (69 kV or above)	8.542
CS-3	Curtailable Service (69 kV or above)	8.545
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GSLDT-3	General Service Large Demand - Time of Use (69 kV or above)	8.552
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EDR	Economic Development Rider	8.800
DSMAR	Demand Side Management Adjustment Rider	8.810
TR	Transformation Rider	8.820
SDTR	Seasonal Demand – Time of Use Rider	8.830
EFEDR	Existing Facility Economic Development Rider	8.900
CISR	Commercial/Industrial Service Rider	8.910
VSP	Voluntary Solar Partnership Pilot Program	8.930

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GENERAL SERVICE - NON DEMAND

RATE SCHEDULE: GS-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose with a demand of 20 kW or less.

SERVICE:

Single phase, 60 hertz and at any available standard distribution voltage. Three phase service will be provided without additional charge unless the Company's line extension policy is applicable thereto. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$10.00
Non-Fuel Energy Charges:	
Base Energy Charge	5.439 ¢ per kWh
Conservation Charge	See Sheet No. 8.030
Capacity Payment Charge	See Sheet No. 8.030
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
General Service Load Management Program (if applicable)	See Sheet No. 8.109
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum:	$10.00
Non-Metered Accounts:	A Customer Charge of $5.00 will apply to those accounts which are billed on an estimated basis and, at the Company's option, do not have an installed meter for measuring electric service. The minimum charge shall be $5.00.

SPECIAL PROVISIONS:

Energy used by commonly owned facilities of condominium, cooperative and homeowners' associations may qualify for the residential rate schedule as set forth on Sheet No. 8.211, Rider CU.

TERM OF SERVICE:

Not less than one (1) billing period.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE - NON DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: GST-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose with a demand of 20 kW or less. This is an optional rate available to General Service - Non Demand customers upon request subject to availability of meters.

SERVICE:

Single phase, 60 hertz and at any available standard distribution voltage. Three phase service will be provided without additional charge unless the Company's line extension policy is applicable thereto. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$10.00	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	10.038 ¢ per kWh	3.441 ¢ per kWh
Conservation Charge	See Sheet No. 8.030	
Capacity Payment Charge	See Sheet No. 8.030	
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
General Service Load Management Program (if applicable)	See Sheet No. 8.109	
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	
Minimum:	$10.00	

Initial service under this rate schedule shall begin on the first scheduled meter reading date following the installation of the time of use meter.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to l0 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.104)

160001 Hearing Exhibits 00331

GENERAL SERVICE DEMAND

RATE SCHEDULE: GSD-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW and less than 500 kW. Customers with a Demand of 20 kW or less may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 21 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$25.00
Demand Charges:	
Base Demand Charge	$9.20 per kW
Capacity Payment Charge	See Sheet No. 8.030, per kW
Conservation Charge	See Sheet No. 8.030, per kW
Non-Fuel Energy Charges:	
Base Energy Charge	2.035 ¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of 20 kW or less who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 21 kW times the Base Demand Charge; therefore the minimum charge is $218.20.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's thermal type meter or, at the Company's option, integrating type meter for the 30-minute period of Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: GSDT-1

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW and less than 500 kW. Customers with Demands of less than 21 kW may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 21 kW. This is an optional rate available to General Service Demand customers upon request subject to availability of meters.

SERVICE:
Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$25.00	
Demand Charges:		
Base Demand Charge	$9.20 per kW of Demand occurring during the On-Peak period.	
Capacity Payment Charge	See Sheet No. 8.030, per kW of Demand occurring during the On-Peak period.	
Conservation Charge	See Sheet No. 8.030, per kW of Demand occurring during the On-Peak period.	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	4.142 ¢ per kWh	1.102 ¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 21 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 21 kW times the Base Demand Charge, therefore the minimum charge is $218.20.

RATING PERIODS:
On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.108)

160001 Hearing Exhibits 00333

GENERAL SERVICE CONSTANT USAGE

RATE SCHEDULE: GSCU-1

AVAILABLE:

In all territory served.

APPLICATION:

Available to General Service - Non Demand customers that maintain a relatively constant kWh usage, and a demand of 20 kW or less. Eligibility is restricted to General Service customers whose Maximum kWh Per Service Day, over the current and prior 23 months, is within 5% of their average monthly kWh per service days calculated over the same 24-month period. Customers under this Rate Schedule shall enter into a General Service Constant Use Agreement. This is an optional Rate Schedule available to General Service customers upon request.

SERVICE:

Single phase, 60 hertz and at any available standard distribution voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$14.00
Non-Fuel Energy Charges:	
Base Energy Charge*	3.507 ¢ per Constant Usage kWh
Conservation Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Capacity Payment Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Environmental Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Additional Charges:	
Fuel Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Storm Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

* The fuel, storm and non-fuel energy charges will be assessed on the Constant Usage kWh

TERM OF SERVICE:

Initial term of service under this rate schedule shall be not less than one (1) billing period, unless there is a termination of service due to a Customer's violation of the General Service Constant Usage Agreement. Upon the Customer's violation of any of the terms of the General Service Constant Usage Agreement, service under this Rate Schedule will be terminated immediately. To terminate service, either party must provide thirty (30) days written notice to the other party prior to the desired termination date. Absent such notice, the term of service shall automatically be extended another billing period. In addition, if service under this Rate Schedule is terminated by either the Customer or the Company, the account may not resume service under this Rate Schedule for a period of at least one (1) year.

DEFINITIONS:

kWh Per Service Day – the total kWh in billing month divided by the number of days in the billing month

Maximum kWh Per Service Day - the highest kWh Per Service Day experienced over the current and prior 23 month billing periods

Constant Usage kWh – the Maximum kWh Per Service Day multiplied by the number of service days in the current billing period

(Continued on Sheet 8.123)

160001 Hearing Exhibits 00334

RESIDENTIAL SERVICE

RATE SCHEDULE: RS-1

AVAILABLE:

In all territory served.

APPLICATION:

For service for all domestic purposes in individually metered dwelling units and in duplexes and triplexes, including the separately-metered non-commercial facilities of a residential Customer (i.e., garages, water pumps, etc.). Also for service to commonly-owned facilities of condominium, cooperative and homeowners' associations as set forth on Sheet No. 8.211, Rider CU.

SERVICE:

Single phase, 60 hertz at available standard distribution voltage. Three phase service may be furnished but only under special arrangements. All residential service required on the premises by Customer shall be supplied through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$7.87
Non-Fuel Charges:	
Base Energy Charge:	
First 1,000 kWh	5.562 ¢ per kWh
All additional kWh	6.562 ¢ per kWh
Conservation Charge	See Sheet No. 8.030
Capacity Payment Charge	See Sheet No. 8.030
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Residential Load Control Program (if applicable)	See Sheet No. 8.217
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum:	$7.87

TERM OF SERVICE:

Not less than one (1) billing period.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

RESIDENTIAL TIME OF USE RIDER – RTR-1
(OPTIONAL)

RIDER: RTR-1

AVAILABLE:
In all territory served.

APPLICATION:

For service for all domestic purposes in individually metered dwelling units and in duplexes and triplexes, including the separately-metered non-commercial facilities of a residential Customer (i.e., garages, water pumps, etc.). Also for service to commonly-owned facilities of condominium, cooperative and homeowners' associations as set forth on Sheet No. 8.211, Rider CU. This is an optional rider available to residential customers served under the RS-1 Rate Schedule subject to availability of meters. Customers taking service under RTR-1 are not eligible for service under Rate Schedule RLP.

SERVICE:
Single phase, 60 hertz at available standard distribution voltage. Three phase may be supplied but only under special arrangements. All residential service required on the premises by Customer shall be supplied through one meter. Resale of service is not permitted hereunder.

Initial service under this rate schedule shall begin on the first scheduled meter reading date following the installation of the time of use meter. The Customer's first bill will reflect the lesser of the charges under Rate Schedule RS-1 or RTR-1.

MONTHLY RATE:

Except for the Customer Charge, all rates and charges under Rate Schedule RS-1 shall apply. In addition, the RTR-1 Customer Charge, the RTR-1 Base Energy and Fuel Charges and Credits applicable to on and off peak usage shall apply.

Customer Charge:	$7.87	
Base Energy Charges/Credits:	On-Peak Period	Off-Peak Period
Base Energy Charge	9.937 ¢ per kWh	(4.420) ¢ per kWh
Additional Charges/Credits:		
RTR Fuel Charge/Credit	See Sheet No. 8.030	
Minimum:	$7.87	

RATING PERIODS:
On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.204)

160001 Hearing Exhibits 00336

GENERAL SERVICE LARGE DEMAND

RATE SCHEDULE: GSLD-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer with a measured demand of 500 kW and less than 2,000 kW. Customers with demands of less than 500 kW may enter an agreement for service under this Rate Schedule based on a Demand Charge for a minimum of 500 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$75.00
Demand Charges:	
Base Demand Charge	$11.00 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	1.585 ¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charges	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is $5,575.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's thermal type meter or, at the Company's option, integrating type meter for the 30-minute period of Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

160001 Hearing Exhibits 00337

GENERAL SERVICE LARGE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE GSLDT-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer with a measured demand of 500 kW and less than 2,000 kW. Customers with demands of less than 500 kW may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 500 kW. This is an optional rate available to General Service Large Demand customers upon request subject to availability of meters.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$75.00	
Demand Charges:		
Base Demand Charge	$11.00 per kW of Demand occurring during the On-Peak period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	2.597 ¢ per kWh	1.143 ¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is $5,575.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.321)

160001 Hearing Exhibits 00338

CURTAILABLE SERVICE
(OPTIONAL)

RATE SCHEDULE: CS-1

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-1 (500 kW - 1,999 kW) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. Customers with demands of at least 200 kW but less than 500 kW may enter an agreement for service under this Rate Schedule based on a Demand Charge for a minimum of 500 kW.

SERVICE:
Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$100.00
Demand Charges:	
Base Demand Charge	$11.00 per kW of Demand.
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	1.585 ¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is $5,600.00.

CURTAILMENT CREDITS:
A monthly credit of ($1.93) per kW is allowed based on the current Non-Firm Demand. The Customer has the option to revise the Firm Demand once during the initial twelve (12) month period. Thereafter, subject to the Term of Service and/or the Provisions for Early Termination, a change to the Firm Demand may be made provided that the revision does not decrease the total amount of Non-Firm Demand during the lesser of: (i) the average of the previous 12 months; or (ii) the average of the number of billing months under this Rate Schedule.

CHARGES FOR NON-COMPLIANCE OF CURTAILMENT DEMAND:
If the Customer records a higher Demand during the current Curtailment Period than the Firm Demand, the Customer will be:

1. Rebilled at $1.93/kW for the prior 36 months or the number of months since the prior Curtailment Period, whichever is less, and
2. Billed a penalty charge of $4.16 kW for the current month.

The kW used for both the rebilling and penalty charge calculations is determined by taking the difference between the maximum Demand during the current Curtailment Period and the Firm Demand for a Curtailment Period.

(Continued on Sheet No. 8.331)

160001 Hearing Exhibits 00339

CURTAILABLE SERVICE - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: CST-1

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-1 (500 kW - 1,999 kW) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. This is an optional Rate Schedule available to Curtailable General Service Customers upon request. Customers with demands of at least 200 kW but less than 500 kW may enter an agreement for service under this Rate Schedule based on a Demand Charge for a minimum of 500 kW

SERVICE:

Single or three phase, 60 hertz and at any available distribution standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$100.00	
Demand Charges:		
Base Demand Charge	$11.00 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	2.597 ¢ per kWh	1.143 ¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is $5,600.00.

RATING PERIODS:

On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.341)

160001 Hearing Exhibits 00340

GENERAL SERVICE LARGE DEMAND

RATE SCHEDULE: GSLD-2

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer with a measured demand of 2,000 kW or more. Customers with demands of less than 2,000 kW may enter an agreement for service under this schedule based on a demand charge for a minimum of 2,000 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$225.00
Demand Charges:	
Base Demand Charge	$11.40 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	1.427 ¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a demand of less than 2,000 kW who enter an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is $23,025.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's metering equipment, for the 30-minute period of the Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE LARGE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: GSLDT-2

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer who has established a measured demand of 2,000 kW or more. Customers with demands of less than 2,000 kW may enter an agreement for service under this schedule based on a demand charge for a minimum of 2,000 kW.

SERVICE:

Three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$225.00	
Demand Charges:		
Base Demand Charge	$11.40 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	2.227 ¢ per kWh	1.112 ¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a demand of less than 2,000 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is $23,025.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.421)

160001 Hearing Exhibits 00342

HIGH LOAD FACTOR – TIME OF USE
(OPTIONAL)

RATE SCHEDULE: HLFT

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW. This is an optional rate schedule available to customers otherwise served under the GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, or GSLDT-2 Rate Schedules.

SERVICE:
Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Annual Maximum Demand	HLFT-1 21-499 kW	HLFT-2 500-1,999 kW	HLFT-3 2,000 kW or greater
Customer Charge:	$25.00	$75.00	$225.00
Demand Charges:			
On-peak Demand Charge	$10.80	$11.60	$11.60
Maximum Demand Charge	$2.30	$2.50	$2.50
Capacity Payment Charge	See Sheet No. 8.030, per kW of On-Peak Demand		
Conservation Charge	See Sheet No. 8.030, per kW of On-Peak Demand		
Non-Fuel Energy Charges:			
On-Peak Period per kWh	1.738 ¢	1.003 ¢	0.903 ¢
Off-Peak Period per kWh	1.102 ¢	0.977 ¢	0.898 ¢
Environmental Charge	See Sheet No. 8.030		
Additional Charges			
Fuel Charge	See Sheet No. 8.030		
Storm Charge	See Sheet No. 8.040		
Franchise Fee	See Sheet No. 8.031		
Tax Clause	See Sheet No. 8.031		

Minimum Charge: The Customer Charge plus the currently effective Demand Charges.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.426)

160001 Hearing Exhibits 00343

CURTAILABLE SERVICE
(OPTIONAL)

RATE SCHEDULE: CS-2

AVAILABLE:

In all territory served.

APPLICATION:

For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-2 (2,000 kW and above) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. Customers with demands of less than 2,000 kW may enter an Agreement for service under this schedule based on a Demand Charge for a minimum of 2,000 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$250.00
Demand Charges:	
Base Demand Charge	$11.40 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	1.427 ¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 2,000 kW who enter an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is $23,050.

CURTAILMENT CREDITS:

A monthly credit of ($1.93) per kW is allowed based on the current Non-Firm Demand. The Customer has the option to revise the Firm Demand once during the initial twelve (12) month period. Thereafter, subject to the Term of Service and/or the Provisions for Early Termination, a change to the Firm Demand may be made provided that the revision does not decrease the total amount of Non-Firm Demand during the lesser of: (i) the average of the previous 12 months; or (ii) the average of the number of billing months under this Rate Schedule.

CHARGES FOR NON-COMPLIANCE OF CURTAILMENT DEMAND:

If the Customer records a higher Demand during the current period than the Firm Demand, then the Customer will be:

1. Rebilled at $1.93 /kW for the prior 36 months or the number of months since the prior Curtailment Period, whichever is less, and
2. Billed a penalty charge of $4.16 /kW for the current month.

The kW used for both the rebilling and penalty charge calculations is determined by taking the difference between the maximum Demand during the current Curtailment Period and the contracted Firm Demand for a Curtailment Period.

(Continued on Sheet No. 8.433)

160001 Hearing Exhibits 00344

CURTAILABLE SERVICE - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: CST-2

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLDT-2 (2,000 kW and above) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. Customers with demands of less than 2,000 kW may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 2,000 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$250.00	
Demand Charges:		
Base Demand Charge	$11.40 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	2.227 ¢ per kWh	1.112 ¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 2,000 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is $23,050.

RATING PERIODS:

On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.441)

160001 Hearing Exhibits 00345

CURTAILABLE SERVICE - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: CST-3

AVAILABLE:

In all territory served.

APPLICATION:

For any commercial or industrial Customer who qualifies for Rate Schedule GSLDT-3 and will curtail this Demand by 200 kW or more upon request of the Company from time to time.

SERVICE:

Three phase, 60 hertz at the available transmission voltage of 69 kV or higher. The Customer will provide and maintain all transformers and related facilities necessary for handling and utilizing the power and energy delivered hereunder. All service required by the Customer at each separate point of delivery served hereunder shall be furnished through one meter at, or compensated to, the available transmission voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$2,025.00	
Demand Charges:		
Base Demand Charge	$9.30 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030.1	
Conservation Charge	See Sheet No. 8.030.1	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	1.227 ¢ per kWh	1.019 ¢ per kWh
Environmental Charge	See Sheet No. 8.030.1	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030.1	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.543)

160001 Hearing Exhibits 00346

CURTAILABLE SERVICE
(OPTIONAL)

RATE SCHEDULE: CS-3

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-3 and will curtail this Demand by 200 kW or more upon request of the Company from time to time.

SERVICE:
Three phase, 60 hertz at the available transmission voltage of 69 kV or higher. The Customer will provide and maintain all transformers and related facilities necessary for handling and utilizing the power and energy delivered hereunder. All service required by the Customer at each separate point of delivery served hereunder shall be furnished through one meter at, or compensated to, the available transmission voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$2,025.00
Demand Charges:	
Base Demand Charge	$9.30 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030.1
Conservation Charge	See Sheet No. 8.030.1
Non-Fuel Energy Charges:	
Base Energy Charge	1.069 ¢ per kWh
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum Charge: The Customer Charge plus the charge for the currently effective Base Demand.

CURTAILMENT CREDITS:
A monthly credit of ($1.93) per kW is allowed based on the current Non-Firm Demand. The Customer has the option to revise the Firm Demand once during the initial twelve (12) month period. Thereafter, subject to the Term of Service and/or the Provisions for Early Termination, a change to the Firm Demand may be made provided that the revision does not decrease the total amount of Non-Firm Demand during the lesser of: (i) the average of the previous 12 months; or (ii) the average of the number of billing months under this Rate Schedule.

CHARGES FOR NON-COMPLIANCE OF CURTAILMENT DEMAND:

If the Customer records a higher Demand during the current Curtailment Period than the Firm Demand, then the Customer will be:

1. Rebilled at $1.93 /kW for the prior 36 months or the number of months since the prior Curtailment Period, whichever is less, and
2. Billed a penalty charge of $4.16 /kW for the current month.

The kW used for both the rebilling and penalty charge calculations is determined by taking the difference between the maximum Demand during the current Curtailment Period and the Firm Demand for a Curtailment Period.

(Continued on Sheet No. 8.546)

160001 Hearing Exhibits 00347

GENERAL SERVICE LARGE DEMAND

RATE SCHEDULE: GSLD-3

AVAILABLE:

In all territory served.

APPLICATION:

For service required for commercial or industrial lighting, power and any other purpose to any Customer who has service supplied at a transmission voltage of 69 kV or higher.

SERVICE:

Three phase, 60 hertz at the available transmission voltage of 69 kV or higher. The Customer will provide and maintain all transformers and related facilities necessary for handling and utilizing the power and energy delivered hereunder. All service required by the Customer at each separate point of delivery served hereunder shall be furnished through one meter at, or compensated to, the available transmission voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$2,000.00
Demand Charges:	
Base Demand Charge	$9.30 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030.1
Conservation Charge	See Sheet No. 8.030.1
Non-Fuel Energy Charges:	
Base Energy Charge	1.069¢ per kWh
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's metering equipment for the 30-minute period of the Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE LARGE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: GSLDT-3

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose to any Customer who has service supplied at a transmission voltage of 69 kV or higher.

SERVICE:

Three phase, 60 hertz at the available transmission voltage of 69 kV or higher. The Customer will provide and maintain all transformers and related facilities necessary for handling and utilizing the power and energy delivered hereunder. All service required by the Customer at each separate point of delivery served hereunder shall be furnished through one meter at, or compensated to, the available transmission voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$2,000.00	
Demand Charges:		
Base Demand Charge	$9.30 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030.1	
Conservation Charge	See Sheet No. 8.030.1	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	1.217 ¢ per kWh	1.016 ¢ per kWh
Environmental Charge	See Sheet No. 8.030.1	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030.1	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand.

RATING PERIODS:

On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.553)

SPORTS FIELD SERVICE
(Closed Schedule)

RATE SCHEDULE: OS-2

AVAILABLE:

In all territory served.

APPLICATION:

This is a transitional rate available to municipal, county and school board accounts for the operation of a football, baseball or other playground, or civic or community auditorium, when all such service is taken at the available primary distribution voltage at a single point of delivery and measured through one meter, and who were active as of October 4, 1981. Customer may also elect to receive service from other appropriate rate schedules.

LIMITATION OF SERVICE:

Offices, concessions, businesses or space occupied by tenants, other than areas directly related to the operations above specified, are excluded hereunder and shall be separately served by the Company at utilization voltage. Not applicable when Rider TR is used.

MONTHLY RATE:

Customer Charge:	$125.00
Non-Fuel Energy Charges:	
Base Energy Charge	7.455 ¢ per kWh
Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum Charge:	$125.00

TERM OF SERVICE:

Pending termination by Florida Public Service Commission Order.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

METROPOLITAN TRANSIT SERVICE

RATE SCHEDULE: MET

AVAILABLE:

For electric service to Metropolitan Miami-Dade County Electric Transit System (METRORAIL) at each point of delivery required for the operation of an electric transit system on continuous and contiguous rights-of-way.

APPLICATION:

Service to be supplied will be three phase, 60 hertz and at the standard primary distribution voltage of 13,200 volts. All service required by Customer at each separate point of delivery served hereunder shall be furnished through one meter reflecting delivery at primary voltage. Resale of service is not permitted hereunder. Rider TR or a voltage discount is not applicable.

MONTHLY RATE:

Customer Charge:	$550.00
Demand Charges:	
Base Demand Charge	$12.70 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030.1
Conservation Charge	See Sheet No. 8.030.1
Non-Fuel Energy Charges:	
Base Energy Charge	1.692 ¢ per kWh
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand.

DEMAND:

The billing Demand is the kW, at each point of delivery, to the nearest whole kW, as determined from the Company's recording type metering equipment, for the period coincident with the 30-minute period of the electric rail transit system's greatest use supplied by the Company during the month adjusted for power factor.

BILLING:

Each point of delivery shall be separately billed according to the monthly charges as stated herein. All billing units related to charges under this rate schedule shall be determined from metering data on a monthly basis and determined for each point of delivery on the same monthly billing cycle day.

TERMS OF SERVICE

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective: January 1, 2017

(Continued from Sheet No. 8.650)

MONTHLY RATE:

Delivery Voltage Level	Distribution below 69 kV		69 kV & above
	CILC-1(G)	CILC-1(D)	CILC-1(T)
Maximum Demand Level	200-499 kW	500 kW & above	
Customer Charge:	$125.00	$225.00	$2,225.00
Demand Charges:			
Base Demand Charges:			
per kW of Maximum Demand	$3.90	$4.00	None
per kW of Load Control On-Peak Demand	$2.60	$2.90	$3.00
per kW of Firm On-Peak Demand	$9.60	$10.50	$11.20
Capacity Payment and Conservation Charge:			
CILC-1(G)	See Sheet No. 8.030.1		
CILC-1(D)	See Sheet No. 8.030.1		
CILC-1(T)	See Sheet No. 8.030.1		
Non-Fuel Energy Charges:			
Base Energy Charges:			
On-Peak Period charge per kWh	1.480 ¢	0.954 ¢	0.900 ¢
Off-Peak Period charge per kWh	1.480 ¢	0.954 ¢	0.900 ¢
Environmental Charge	See Sheet No. 8.030.1		
Additional Charges:			
Fuel Charge	See Sheet No. 8.030.1		
Storm Charge	See Sheet No. 8.040		
Franchise Fee	See Sheet No. 8.031		
Tax Clause	See Sheet No. 8.031		

Minimum: The Customer Charge plus the Base Demand Charges.

(Continued on Sheet No. 8.652)

160001 Hearing Exhibits 00352

COMMERCIAL/INDUSTRIAL DEMAND REDUCTION RIDER (CDR)
(OPTIONAL)

AVAILABLE:

In all territory served. Available to any commercial or industrial customer receiving service under Rate Schedules GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, or HLFT through the execution of a Commercial/Industrial Demand Reduction Rider Agreement in which the load control provisions of this rider can feasibly be applied.

LIMITATION OF AVAILABILITY:

This Rider may be modified or withdrawn subject to determinations made under Commission Rules 25-17.0021(4), F.A.C., Goals for Electric Utilities and 25-6.0438, F.A.C., Non-Firm Electric Service - Terms and Conditions or any other Commission determination.

APPLICATION:

For electric service provided to any commercial or industrial customer receiving service under Rate Schedule GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, or HLFT who as a part of the Commercial/Industrial Demand Reduction Rider Agreement between the Customer and the Company, agrees to allow the Company to control at least 200 kW of the Customer's load, or agrees to operate Backup Generation Equipment (see Definitions) and designate (if applicable) additional controllable demand to serve at least 200 kW of the Customer's own load during periods when the Company is controlling load. A Customer shall enter into a Commercial/Industrial Reduction Demand Rider Agreement with the Company to be eligible for this Rider. To establish the initial qualification for this Rider, the Customer must have had a Utility Controlled Demand during the summer Controllable Rating Period (April 1 through October 31) for at least three out of seven months of at least 200 kW greater than the Firm Demand level specified in Section 4 of the Commercial/Industrial Demand Reduction Rider Agreement. The Utility Controlled Demand shall not be served on a firm service basis until service has been terminated under this Rider.

LIMITATION OF SERVICE:

Customers participating in the General Service Load Management Program (FPL "Business On Call" Program) are not eligible for this Rider.

MONTHLY RATE:

All rates and charges under Rate Schedules GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, HLFT shall apply. In addition, the applicable Monthly Administrative Adder and Utility Controlled Demand Credit shall apply.

MONTHLY ADMINISTRATIVE ADDER:

Rate Schedule	Adder
GSD-1	$100.00
GSDT-1, HLFT (21-499 kW)	$100.00
GSLD-1, GSLDT-1, HLFT (500-1,999 kW)	$150.00
GSLD-2, GSLDT-2, HLFT (2,000 kW or greater)	$75.00
GSLD-3, GSLDT-3	$225.00

UTILITY CONTROLLED DEMAND CREDIT:

A monthly credit of ($8.20) per kW is allowed based on the Customer's Utility Controlled Demand.

UTILITY CONTROLLED DEMAND:

The Utility Controlled Demand for a month in which there are no load control events during the Controllable Rating Period shall be the sum of the Customer's kWh usage during the hours of the applicable Controllable Rating Period, divided by the total number of hours in the applicable Controllable Rating Period, less the Customer's Firm Demand.

In the event of Load Control occurring during the Controllable Rating Period, the Utility Controlled Demand shall be the sum of the Customer's kWh usage during the hours of the applicable Controllable Rating Period less the sum of the Customer's kWh usage during the Load Control Period, divided by the number of non-load control hours occurring during the applicable Controllable Rating Period, less the Customer's Firm Demand.

(Continued on Sheet No. 8.681)

160001 Hearing Exhibits 00353

STREET LIGHTING

RATE SCHEDULE: SL-1

AVAILABLE:

In all territory served.

APPLICATION:

For lighting streets and roadways, whether public or private, which are thoroughfares for normal flow of vehicular traffic. Lighting for other applications such as: municipally and privately-owned parking lots; parks and recreational areas; or any other area not expressly defined above, is not permitted under this schedule except for lighting in such an application that was already under this schedule prior to July 9, 1992. Lamp replacement and energy-only service is available to existing customer facilities taking service under this rate prior to January 1, 2017.

TYPE OF INSTALLATION:

FPL-owned fixtures normally will be mounted on poles of FPL's existing distribution system and served from overhead wires. On request of the Customer, FPL will provide special poles or underground wires at the charges specified below. Customer-owned systems will be of a standard type and design, permitting service and lamp replacement at no abnormal cost to FPL.

SERVICE:

Service includes lamp renewals, patrol, energy from dusk each day until dawn the following day and maintenance of FPL-owned Street Lighting Systems.

LIMITATION OF SERVICE:

For Mercury Vapor, Fluorescent and Incandescent luminaires, no additions or changes in specified lumen output on existing installations will be permitted under this schedule after October 4, 1981 except where such additional lights are required in order to match existing installations.

Stand-by or resale service is not permitted hereunder.

CUSTOMER CONTRIBUTIONS:

A Contribution-in-Aid-of-Construction (CIAC) will be required for:

a) the differential cost between employing rapid construction techniques in trenching, backfilling and pole installation work where no obstructions exist, and the added cost to overcome obstructions such as sprinkler systems, paved surfaces (such as sidewalks, curbs, gutters, and roadways), landscaping, sodding and other obstructions encountered along the Street Light System installation route, including repair and replacement. If the Customer elects to perform work such as trenching and restoration, they will be reimbursed by FPL with a credit (not to exceed the total CIAC cost) for the value of this work as determined by FPL;

b) the installation cost of any new overhead distribution facilities and/or the cost of alterations to existing distribution facilities which are required in order to serve the Street Lighting System less four (4) times the additional annual non-fuel energy revenue generated by the installation or alteration of the Street Lighting System, plus where underground facilities are installed, the differential installation cost between underground and overhead distribution facilities.

These costs shall be paid by the Customer prior to the initiation of any construction work by FPL. The Customer shall also pay any additional costs associated with design modifications requested after the original estimate has been made.

(Continued on Sheet No. 8.716)

160001 Hearing Exhibits 00354

(Continued from Sheet No. 8.715)

REMOVAL OF FACILITIES:

If Street Lighting facilities are removed either by Customer request or termination or breach of the agreement, the Customer shall pay FPL an amount equal to the original installed cost of the removed facilities less any salvage value and any depreciation (based on current depreciation rates as approved by the Florida Public Service Commission) plus removal cost.

MONTHLY RATE:

Luminaire Type		Lamp Size Initial Lumens/Watts		kWh/Mo. Estimate	Charge for FPL-Owned Unit ($) Fixtures	Maintenance	Energy Non-Fuel **	Total ***	Charge for Customer-Owned Unit $) **** Relamping/ Energy	Energy Only
High Pressure Sodium Vapor		6,300	70	29	$3.89	1.85	0.83	6.57	$2.69	$0.83
" "		9,500	100	41	$3.96	1.86	1.17	6.99	$3.04	$1.17
" "		16,000	150	60	$4.08	1.89	1.71	7.68	$3.61	$1.71
" "		22,000	200	88	$6.18	2.41	2.51	11.10	$4.90	$2.51
" "		50,000	400	168	$6.24	2.42	4.79	13.45	$7.19	$4.79
" "	*	27,500	250	116	$6.58	2.63	3.31	12.52	$5.91	$3.31
" "	*	140,000	1,000	411	$9.90	4.71	11.71	26.32	$16.46	$11.71
Mercury Vapor	*	6,000	140	62	$3.07	1.66	1.77	6.50	$3.44	$1.77
" "	*	8,600	175	77	$3.12	1.66	2.19	6.97	$3.86	$2.19
" "	*	11,500	250	104	$5.21	2.40	2.96	10.57	$5.37	$2.96
" "	*	21,500	400	160	$5.18	2.36	4.56	12.10	$6.93	$4.56

* These units are closed to new FPL installations.
** The non-fuel energy charge is 2.850 ¢ per kWh.
*** Bills rendered based on "Total" charge. Unbundling of charges is not permitted.
**** New customer-owned facilities are closed to this rate effective January 1, 2017.

Charges for other FPL-owned facilities:

Wood pole used only for the street lighting system	$4.92
Concrete pole used only for the street lighting system	$6.74
Fiberglass pole used only for the street lighting system	$7.98
Steel pole used only for the street lighting system *	$6.74
Underground conductors not under paving	3.810 ¢ per foot
Underground conductors under paving	9.310 ¢ per foot

The Underground conductors under paving charge will not apply where a CIAC is paid pursuant to section "a)" under "Customer Contributions." The Underground conductors not under paving charge will apply in these situations.

(Continued on Sheet No. 8.717)

160001 Hearing Exhibits 00355

(Continued from Sheet No. 8.716)

On Customer-owned Street Lighting Systems, where Customer contracts to relamp at no cost to FPL, the Monthly Rate for non-fuel energy shall be 2.850 ¢ per kWh of estimated usage of each unit plus adjustments. On Street Lighting Systems, where the Customer elects to install Customer-owned monitoring systems, the Monthly Rate for non-fuel energy shall be 2.850 ¢ per kWh of estimated usage of each monitoring unit plus adjustments. The minimum monthly kWh per monitoring device will be 1 kilowatt-hour per month, and the maximum monthly kWh per monitoring device will be 5 kilowatt-hours per month.

During the initial installation period:
Facilities in service for 15 days or less will not be billed;
Facilities in service for 16 days or more will be billed for a full month.

WILLFUL DAMAGE:

Upon the **second** occurrence of willful damage to any FPL-owned facilities, the Customer will be responsible for the cost incurred for repair or replacement. If the lighting fixture is damaged, based on prior written instructions from the Customer, FPL will:

a) Replace the fixture with a shielded cutoff cobrahead. The Customer shall pay $280.00 for the shield plus all associated costs. However, if the Customer chooses to have the shield installed after the first occurrence, the Customer shall only pay the $280.00 cost of the shield; or

b) Replace with a like unshielded fixture. For this, and each subsequent occurrence, the Customer shall pay the costs specified under "Removal of Facilities"; or

c) Terminate service to the fixture.

Option selection shall be made by the Customer in writing and apply to all fixtures which FPL has installed on the Customer's behalf. Selection changes may be made by the Customer at any time and will become effective ninety (90) days after written notice is received.

Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

SPECIAL CONDITIONS:

Customers whose lights are turned off during sea turtle nesting season will receive a credit equal to the fuel charges associated with the fixtures that are turned off.

TERM OF SERVICE:

Initial term of ten (10) years with automatic, successive five (5) year extensions unless terminated in writing by either FPL or the Customer at least ninety (90) days prior to the current term's expiration.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

160001 Hearing Exhibits 00356

STREET LIGHTING METERED SERVICE

RATE SCHEDULE: SL-1M

AVAILABLE:

In all territory served.

APPLICATION:

For customer-owned lighting of streets and roadways, whether public or private, which are thoroughfares for normal flow of vehicular traffic. Lighting for other applications such as: municipally and privately-owned parking lots; parks and recreational areas; or any other area not expressly defined above, is not permitted under this schedule.

SERVICE:

Single phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$13.00
Non-Fuel Energy Charges:	
Base Energy Charge	2.795 ¢ per kWh
Conservation Charge	See Sheet No. 8.030
Capacity Payment Charge	See Sheet No. 8.030
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum:	$13.00

TERM OF SERVICE:

Not less than one (1) year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

PREMIUM LIGHTING

RATE SCHEDULE: PL-1

AVAILABLE:

In all territory served.

APPLICATION:

FPL-owned lighting facilities not available under rate schedule SL-1 and OL-1. To any Customer for the sole purpose of lighting streets, roadways and common areas, other than individual residential locations. This includes but is not limited to parking lots, homeowners association common areas, or parks.

SERVICE:

Service will be unmetered and will include lighting installation, lamp replacement and facilities maintenance for FPL-owned lighting systems. It will also include energy from dusk each day until dawn the following day.

The Company, while exercising reasonable diligence at all times to furnish service hereunder, does not guarantee continuous lighting and will not be liable for damages for any interruption, deficiency or failure of service, and reserves the right to interrupt service at any time for necessary repairs to lines or equipment.

LIMITATION OF SERVICE:

Installation shall be made only when, in the judgement of the Company, the location and the type of the facilities are, and will continue to be, easily and economically accessible to the Company equipment and personnel for both construction and maintenance.

Stand-by, non-firm, or resale service is not permitted hereunder.

TERM OF SERVICE:

The term of service is (20) twenty years. At the end of the term of service, the Customer may elect to execute a new agreement based on the current estimated replacement costs. The Company will retain ownership of these facilities.

FACILITIES PAYMENT OPTION:

The Customer will pay for the facilities in a lump sum in advance of construction. The amount will be the Company's total work order cost for these facilities times the Present Value Revenue Requirement (PVRR) multiplier of 1.1942. Monthly Maintenance and Energy charges will apply for the term of service.

FACILITIES SELECTION:

Facilities selection shall be made by the Customer in writing by executing the Company's Premium Lighting Agreement.

(Continued on Sheet No. 8.721)

160001 Hearing Exhibits 00358

(Continued from Sheet No. 8.720)

MONTHLY RATE :

Facilities:

Paid in full:	Monthly rate is zero, for Customer's who have executed a Premium Lighting Agreement before March 1, 2010:
10 years payment option:	1.358% of total work order cost.
20 years payment option:	0.920% of total work order cost.
Maintenance:	FPL's estimated costs of maintaining lighting facilities.
Billing:	FPL reserves the right to assess a charge for the recovery of any dedicated billing system developed solely for this rate.
Energy:	KWH Consumption for fixtures shall be estimated using the following formula:

$$KWH = \frac{\text{Unit Wattage (usage)} \times 353.3 \text{ hours per month}}{1000}$$

Non-Fuel Energy	2.850 ¢/kWh
Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

During the initial installation period:
Facilities in service for 15 days or less will not be billed;
Facilities in service for 16 days or more will be billed for a full month.

MINIMUM MONTHLY BILL:

The minimum monthly bill shall be the applicable Facilities Maintenance and Billing charges.

(Continued on Sheet No. 8.722)

160001 Hearing Exhibits 00359

(Continued from Sheet No. 8.721)

EARLY TERMINATION:

If the Customer no longer wishes to receive service under this schedule, the Customer may terminate the Premium Lighting Agreement by giving at least (90) ninety days advance written notice to the Company. Upon early termination of service, the Customer shall pay an amount computed by applying the following Termination Factors to the installed cost of the facilities, based on the year in which the Agreement was terminated. These Termination Factors will not apply to Customers who elected to pay for the facilities in a lump sum in lieu of a monthly payment.

FPL may also charge the Customer for the cost to the utility for removing the facilities.

Ten (10) Years Payment Option	Termination Factor	Twenty (20) Years Payment Option	Termination Factor
1	1.1942	1	1.1942
2	1.0312	2	1.0838
3	0.9475	3	1.0568
4	0.8575	4	1.0277
5	0.7605	5	0.9964
6	0.6560	6	0.9627
7	0.5435	7	0.9264
8	0.4224	8	0.8873
9	0.2919	9	0.8452
10	0.1513	10	0.7999
>10	0.0000	11	0.7510
		12	0.6984
		13	0.6418
		14	0.5808
		15	0.5151
		16	0.4443
		17	0.3681
		18	0.2861
		19	0.1977
		20	0.1025
		>20	0.0000

WILLFUL DAMAGE:

In the event of willful damage to these facilities, FPL will provide the initial repair of each installed item at its expense. Upon the second occurrence of willful damage, and subsequent occurrence to these FPL-owned facilities, the Customer will be responsible for the cost for repair or replacement.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

OUTDOOR LIGHTING

RATE SCHEDULE OL-1

AVAILABLE:

In all territory served.

APPLICATION:

For year-round outdoor security lighting of yards, walkways and other areas. Lights to be served hereunder shall be at locations which are easily and economically accessible to Company vehicles and personnel for construction and maintenance.

It is intended that Company-owned security lights will be installed on existing Company-owned electric facilities, or short extension thereto, in areas where a street lighting system is not provided or is not sufficient to cover the security lighting needs of a particular individual or location. Where more extensive security lighting is required, such as for large parking lots or other commercial areas, the Customer will provide the fixtures, supports and connecting wiring; the Company will connect to the Customer's system and provide the services indicated below.

SERVICE:

Service includes lamp renewals, energy from approximately dusk each day until approximately dawn the following day, and maintenance of Company-owned facilities. The Company will replace all burned-out lamps and will maintain its facilities during regular daytime working hours as soon as practicable following notification by the Customer that such work is necessary. The Company shall be permitted to enter the Customer's premises at all reasonable times for the purpose of inspecting, maintaining, installing and removing any or all of its equipment and facilities.

The Company, while exercising reasonable diligence at all times to furnish service hereunder, does not guarantee continuous lighting and will not be liable for damages for any interruption, deficiency or failure of service, and reserves the right to interrupt service at any time for necessary repairs to lines or equipment.

LIMITATION OF SERVICE:

This schedule is not available for service normally supplied on the Company's standard street lighting schedules. Company-owned facilities will be installed only on Company-owned poles. Customer-owned facilities will be installed only on Customer-owned poles. Overhead conductors will not be installed in any area designated as an underground distribution area, or any area, premises or location served from an underground source. Customer must have an active house or premise account associated with this service. Stand-by or resale service not permitted hereunder.

MONTHLY RATE:

Luminaire Type	Lamp Size Initial Lumens/Watts		KWH/Mo. Estimate	Charge for Company-Owned Unit ($) Fixtures	Maintenance	Energy Non-Fuel **	Total	Charge for Customer-Owned Unit ($) Relamping/ Energy	Energy Only
High Pressure Sodium Vapor	6,300	70	29	$5.05	$1.90	$0.84	7.79	$2.69	$0.84
" "	9,500	100	41	$5.16	$1.90	$1.19	8.25	$3.04	$1.19
" "	16,000	150	60	$5.34	$1.93	$1.74	9.01	$3.62	$1.74
" "	22,000	200	88	$7.77	$2.49	$2.55	12.81	$4.98	$2.55
" "	50,000	400	168	$8.27	$2.45	$4.88	15.60	$7.27	$4.88
" " *	12,000	150	60	$5.34	$1.93	$1.74	9.01	$3.89	$1.74
Mercury Vapor *	6,000	140	62	$3.88	$1.70	$1.80	7.38	$3.46	$1.80
" " *	8,600	175	77	$3.90	$1.70	$2.23	7.83	$3.89	$2.23
" " *	21,500	400	160	$6.39	$2.40	$4.64	13.43	$6.98	$4.64

* These units are closed to new Company installations.

** The non-fuel energy charge is 2.902¢ per kWh.

(Continued on Sheet No. 8.726)

160001 Hearing Exhibits 00361

(Continued from Sheet No. 8.725)

Charges for other Company-owned facilities:

Wood pole and span of conductors:	$11.14
Concrete pole and span of conductors:	$15.03
Fiberglass pole and span of conductors:	$17.68
Steel pole used only for the street lighting system *	$15.03
Underground conductors (excluding trenching)	$0.085 per foot
Down-guy, Anchor and Protector	$10.13

For Customer-owned outdoor lights, where the Customer contracts to relamp at no cost to FPL, the monthly rate for non-fuel energy shall be $2.902¢ per kWh of estimated usage of each unit plus adjustments.

Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Clause	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

TERM OF SERVICE:

Not less than one year. In the event the Company installs any facilities for which there is an added monthly charge, the Term of Service shall be for not less than three years.

If the Customer terminates service before the expiration of the initial term of the agreement, the Company may require reimbursement for the total expenditures made to provide such service, plus the cost of removal of the facilities installed less the salvage value thereof, and less credit for all monthly payments made for Company-owned facilities.

WILLFUL DAMAGE:

In the event of willful damage to these facilities, FPL will provide the initial repair of each installed item at its expense. Upon the second occurrence of willful damage, and subsequent occurrence to these FPL-owned facilities, the Customer will be responsible for the cost for repair or replacement.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

COMPANY-OWNED FACILITIES:

Company-owned luminaires normally will be mounted on Company's existing distribution poles and served from existing overhead wires. The Company will provide one span of secondary conductor from existing secondary facilities to a Company-owned light at the Company's expense. When requested by the Customer, and at the option of the Company, additional spans of wire or additional poles or underground conductors may be installed by the Company upon agreement by the Customer to use the facilities for a minimum of three years and pay each month the charges specified under MONTHLY RATE.

MONTHLY RATE

The Customer will make a lump sum payment for the cost of changes in the height of existing poles or the installation of additional poles in the Company's distribution lines or the cost of any other facilities required for the installation of lights to be served hereunder.

(Continued on Sheet No. 8.727)

160001 Hearing Exhibits 00362

(Continued from Sheet No. 8.726)

At the Customer request, the Company will upgrade to a higher level of illumination without a service charge when the changes are consistent with good engineering practices. The Customer will pay the Company the net costs incurred in making other lamp size changes. In all cases where luminaries are replaced, the Customer will sign a new service agreement. Billing on the rate for the new luminaire or lamp size will begin as of the next regular billing date. A luminaire may be relocated at the Customer's request upon payment by the Customer of the costs of removal and reinstallation.

The Company will not be required to install equipment at any location where the service may be objectionable to others. If it is found after installation that the light is objectionable, the Company may terminate the service.

When the Company relocates or removes its facilities to comply with governmental requirements, or for any other reason, either the Company or the Customer shall have the right, upon written notice, to discontinue service hereunder without obligation or liability.

SPECIAL CONDITIONS:

Customers whose lights are turned off during sea turtle nesting season will receive a credit equal to the fuel charges associated with the fixtures that are turned off.

CUSTOMER-OWNED FACILITIES:

Customer-owned luminaires and other facilities will be of a type and design specified by the Company to permit servicing and lamp replacement at no abnormal cost. The Customer will provide all poles, fixtures, initial lamps and controls, and circuits up to the point of connection to the Company's supply lines, and an adequate support for the Company-owned service conductors.

The Company will provide an overhead service drop from its existing secondary conductors to the point of service designated by the Company for Customer-owned lights. Underground service conductors will be installed in lieu of the overhead conductors at the Customer's request, and upon payment by the Customer of the installed cost of the underground conductors after allowance for the cost of equivalent overhead service conductors and any trenching and backfilling provided by the Customer.

DEFINITIONS:

A "Luminaire," as defined by the Illuminating Engineering Society, is a complete lighting unit consisting of a lamp (bulb), together with parts designed to distribute the light, to position and protect the lamp, and connect the lamp to the power supply.

A "Conventional" luminaire is supported by a bracket that is mounted on the side of an ordinary wood pole or an ornamental pole. This is the only type of luminaire offered where service is to be supplied from overhead conductors, although this luminaire may also be used when service is supplied from underground conductors.

A "Contemporary" luminaire is of modern design and is mounted on top of an ornamental pole. Underground conductors are required.

A "Traditional" luminaire resembles an Early American carriage lantern and is mounted on top of a pole. It requires an ornamental pole and underground conductors to a source of supply.

An "Ornamental" pole is one made of concrete or fiberglass.

160001 Hearing Exhibits 00363

TRAFFIC SIGNAL SERVICE

RATE SCHEDULE: SL-2

AVAILABLE:

In all territory served.

APPLICATION:

Service for traffic signal lighting where the signal system and the circuit to connect with Company's existing supply lines are installed, owned and maintained by Customer and were active prior to January 1, 2017.

SERVICE:

Single phase, 60 hertz and approximately 120/240 volts or higher, at Company's option.

MONTHLY RATE:

Non-Fuel Energy Charges:

Base Energy Charge	4.731 ¢ per kWh
Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1

Additional Charges:

Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: $3.24 at each point of delivery.

Note: During the initial installation period of facilities:
Lights and facilities in service for 15 days or less will not be billed;
Lights and facilities in service for 16 days or more will be billed for a full month.

CALCULATED USAGE:

The Calculated Usage at each point of delivery shall be determined by operating tests or utilization of manufacturers' ratings and specifications. The monthly operation shall be based on a standard of 730 hours; however, that portion of the operation which is on a noncontinuous basis shall be adjusted to reflect such operation.

TERM OF SERVICE:

Not less than one (1) billing period.

NOTICE OF CHANGES:

The Customer shall notify the Company at least 30 days prior to any change in rating of the equipment served or the period of operation.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

TRAFFIC SIGNAL METERED SERVICE

RATE SCHEDULE: SL-2M

AVAILABLE:

In all territory served.

APPLICATION:

Service for traffic signal lighting where the signal system and the circuit to connect with Company's existing supply lines are installed, owned and maintained by Customer.

SERVICE:

Single phase, 60 hertz and approximately 120/240 volts or higher, at Company's option.

MONTHLY RATE:

Customer Charge:	$6.00
Non-Fuel Energy Charges:	
Base Energy Charge	4.596 ¢ per kWh
Conservation Charge	See Sheet No. 8.030
Capacity Payment Charge	See Sheet No. 8.030
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum:	$6.00

TERM OF SERVICE:

Not less than one (1) year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

RECREATIONAL LIGHTING

(Closed Schedule)

RATE SCHEDULE: RL-1

AVAILABLE:

In all territory served. Available to any customer, who, as of January 16, 2001, was either taking service pursuant to this schedule or had a fully executed Recreational Lighting Agreement with the Company.

APPLICATION:

For FPL-owned facilities for the purpose of lighting community recreational areas. This includes, but is not limitied to, baseball, softball, football, soccer, tennis, and basketball.

SERVICE:

Service will be metered and will include lighting installation, lamp replacement and facilities maintenance for FPL-owned lighting systems.

The Company, while exercising reasonable diligence at all times to furnish service hereunder, does not guarantee continuous lighting and will not be liable for damages for any interruption, deficiency or failure of service, and reserves the right to interrupt service at any time for necessary repairs to lines or equipment.

LIMITATION OF SERVICE:

Installation shall be made only when, in the judgement of the Company, the location and the type of the facilities are, and will continue to be, easily and economically accessible to the Company equipment and personnel for both construction and maintenance.

Stand-by, non-firm, or resale service is not permitted hereunder.

TERM OF SERVICE:

The term of service is (20) twenty years. At the end of the term of service, the Customer may elect to execute a new Agreement based on the current estimated replacement costs. The Company will retain ownership of these facilities.

FACILITIES PAYMENT OPTION:

The Customer will pay for the facilities in a lump sum in advance of construction. The amount will be the Company's total work order cost for these facilities times the Present Value Revenue Requirement (PVRR) multiplier of 1.1942. Monthly Maintenance and energy charges will apply for the term of service.

FACILITIES SELECTION:

Facilities selection shall be made by the Customer in writing by executing the Company's Recreational Lighting Agreement.

(Continued on Sheet No. 8.744)

160001 Hearing Exhibits 00366

(Continued from Sheet No. 8.743)

MONTHLY RATE :

Facilities:

Paid in full:	Monthly rate is zero.
10 years payment option:	1.358% of total work order cost.*
20 years payment option:	0.920% of total work order cost.*

* Both (10) ten and (20) twenty year payment options are closed to new service, and are only available for the duration of the term of service of those customers that have fully executed a Recreational Lighting Agreement with the Company before January 16, 2001.

Maintenance:	FPL's estimated costs of maintaining lighting facilities.
Billing:	FPL reserves the right to assess a charge for the recovery of any dedicated billing system developed solely for this rate.
Charge Per Month:	Company's otherwise applicable general service rate schedule.
Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

MINIMUM MONTHLY BILL:

As provided in the otherwise applicable rate schedule, plus the Facilities Maintenance and Billing charges.

(Continued on Sheet No. 8.745)

(Continued from Sheet No. 8.744)

EARLY TERMINATION:

If the Customer no longer wishes to receive service under this schedule, the Customer may terminate the Recreational Lighting Agreement by giving at least (90) ninety days advance written notice to the Company. Upon early termination of service, the Customer shall pay an amount computed by applying the following Termination Factors to the installed cost of the facilities, based on the year in which the Agreement was terminated. These Termination Factors will not apply to Customers who elected to pay for the facilities in a lump sum in lieu of a monthly payment.

FPL may also charge the Customer for the cost to the utility for removing the facilities.

Ten (10) Years Payment Option	Termination Factor	Twenty (20) Years Payment Option	Termination Factor
1	1.1942	1	1.1942
2	1.0312	2	1.0838
3	0.9475	3	1.0568
4	0.8575	4	1.0277
5	0.7605	5	0.9964
6	0.6560	6	0.9627
7	0.5435	7	0.9264
8	0.4224	8	0.8873
9	0.2919	9	0.8452
10	0.1513	10	0.7999
>10	0.0000	11	0.7510
		12	0.6984
		13	0.6418
		14	0.5808
		15	0.5151
		16	0.4443
		17	0.3681
		18	0.2861
		19	0.1977
		20	0.1025
		>20	0.0000

WILLFUL DAMAGE:

In the event of willful damage to these facilities, FPL will provide the initial repair of each installed item at its expense. Upon the second occurrence of willful damage, and subsequent occurrence to these FPL-owned facilities, the Customer will be responsible for the cost for repair or replacement.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

STANDBY AND SUPPLEMENTAL SERVICE

RATE SCHEDULE: SST-1

AVAILABLE:

In all territory served by the Company. Service under this rate schedule is on a customer by customer basis subject to the completion of arrangements necessary for implementation.

APPLICATION:

For electric service to any Customer, at a point of delivery, whose electric service requirements for the Customer's load are supplied or supplemented from the Customer's generation equipment at that point of service and require standby and/or supplemental service. For purposes of determining applicability of this rate schedule, the following definitions shall be used:

(1) "Standby Service" means electric energy or capacity supplied by the Company to replace energy or capacity ordinarily generated by the Customer's own generation equipment during periods of either scheduled (maintenance) or unscheduled (backup) outages of all or a portion of the Customer's generation.

(2) "Supplemental Service" means electric energy or capacity supplied by the Company in addition to that which is normally provided by the Customer's own generation equipment.

A Customer is required to take service under this rate schedule if the Customer's total generation capacity is more than 20% of the Customer's total electrical load and the Customer's generators are not for emergency purposes only.

Customers taking service under this rate schedule shall enter into a Standby and Supplemental Service Agreement ("Agreement"); however, failure to execute such an agreement will not pre-empt the application of this rate schedule for service.

SERVICE:

Three phase, 60 hertz, and at the available standard voltage. All service supplied by the Company shall be furnished through one metering point. Resale of service is not permitted hereunder.

Transformation Rider - TR, Sheet No. 8.820, does not apply to Standby Service.

MONTHLY RATE:

STANDBY SERVICE

Delivery Voltage:	Below 69 kV			69kV & Above
Contract Standby Demand:	SST-1(D1) Below 500 kW	SST-1(D2) 500 to 1,999 kW	SST-1(D3) 2,000 kW & Above	SST-1(T) All Levels
Customer Charge:	$125.00	$125.00	$425.00	$1,800.00
Demand Charges:				
Base Demand Charges:				
Distribution Demand Charge per kW of Contract Standby Demand	$3.00	$3.00	$3.00	N/A
Reservation Demand Charge per kW	$1.48	$1.48	$1.48	$1.33
Daily Demand Charge per kW for each daily maximum On-Peak Standby Demand	$0.70	$0.70	$0.70	$0.44
Capacity Payment and Conservation Charges	See Sheet No. 8.030.1			

(Continued on Sheet No. 8.751)

160001 Hearing Exhibits 00369

(Continued from Sheet No. 8.750)

Delivery Voltage:	Below 69 kV			69 kV & Above
	SST-1(D1)	SST-1(D2)	SST-1(D3)	SST-1(T)
Contract Standby Demand:	Below 500 kW	500 to 1,999 kW	2,000 kW & Above	All Levels
Non-Fuel Energy Charges:				
Base Energy Charges:				
On-Peak Period charge per kWh	0.707 ¢	0.707 ¢	0.707 ¢	0.707 ¢
Off-Peak Period charge per kWh	0.707 ¢	0.707 ¢	0.707 ¢	0.707 ¢

Environmental Charge — See Sheet No. 8.030.1

Additional Charges:

Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the Base Demand Charges.

DEMAND CALCULATION:

The Demand Charge for Standby Service shall be (1) the charge for Distribution Demand **plus** (2) the greater of the sum of the Daily Demand Charges **or** the Reservation Demand Charge times the maximum On-Peak Standby Demand actually registered during the month **plus** (3) the Reservation Demand Charge times the difference between the Contract Standby Demand and the maximum On-Peak Standby Demand actually registered during the month.

SUPPLEMENTAL SERVICE

Supplemental Service shall be the total power supplied by the Company minus the Standby Service supplied by the Company during the same metering period. The charge for all Supplemental Service shall be calculated by applying the applicable retail rate schedule, excluding the customer charge.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

CONTRACT STANDBY DEMAND:

The level of Customer's generation requiring Standby Service as specified in the Agreement. This Contract Standby Demand will not be less than the maximum load actually served by the Customer's generation during the current month or prior 23-month period less the amount specified as the Customer's load which would not have to be served by the Company in the event of an outage of the Customer's generation equipment. For a Customer receiving only Standby Service as identified under Special Provisions, the Contract Standby Demand shall be maximum load actually served by the Company during the current month or prior 23-month period.

A Customer's Contract Standby Demand may be re-established to allow for the following adjustments:

1. Demand reduction resulting from the installation of FPL Demand Side Management Measures or FPL Research Project efficiency measures; or

(Continued on Sheet No. 8.752)

160001 Hearing Exhibits 00370

INTERRUPTIBLE STANDBY AND SUPPLEMENTAL SERVICE
(OPTIONAL)

RATE SCHEDULE: ISST-1

AVAILABLE:

In all territory served by the Company. Service under this rate schedule is on a customer by customer basis subject to the completion of arrangements necessary for implementation.

LIMITATION OF AVAILABILITY:

This schedule may be modified or withdrawn subject to determinations made under Commission Rule 25-6.0438, F.A.C., Non-Firm Electric Service - Terms and Conditions or any other Commission determination.

APPLICATION:

A Customer who is eligible to receive service under the Standby and Supplemental Service (SST-1) rate schedule may, as an option, take service under this rate schedule, unless the Customer has entered into a contract to sell firm capacity and/or energy to the Company, and the Customer cannot restart its generation equipment without power supplied by the Company, in which case the Customer may only receive Standby and Supplemental Service under the Company's SST-1 rate schedule.

Customers taking service under this rate schedule shall enter into an Interruptible Standby and Supplemental Service Agreement ("Agreement"). This interruptible load shall not be served on a firm service basis until service has been terminated under this rate schedule.

SERVICE:

Three phase, 60 hertz, and at the available standard voltage.

A designated portion of the Customer's load served under this schedule is subject to interruption by the Company. Transformation Rider-TR, where applicable, shall only apply to the Customer's Contract Standby Demand for delivery voltage below 69 kV. Resale of service is not permitted hereunder.

MONTHLY RATE:

STANDBY SERVICE Delivery Voltage:		Distribution Below 69 kV ISST-1(D)	Transmission 69 kV & Above ISST-1(T)
Customer Charge:		$425.00	$1,800.00
Demand Charges:			
Base Demand Charges:			
Distribution Demand Charge per kW of Contract Standby Demand		$3.00	N/A
Reservation Demand Charge per kW of Interruptible Standby Demand		$0.25	$0.30
Reservation Demand Charge per kW of Firm Standby Demand		$1.48	$1.33
Daily Demand Charge per kW for each daily maximum On-Peak Interruptible Standby Demand		$0.70	$0.44
Daily Demand Charge per kW for each daily maximum On-Peak Firm Standby Demand		$0.12	$0.12
Capacity Payment and Conservation Charges	See Sheet No. 8.030.1		
Non-Fuel Energy Charges:			
Base Energy Charges:			
On-Peak Period charge per kWh		0.707 ¢	0.707 ¢
Off-Peak Period charge per kWh		0.707 ¢	0.707 ¢
Environmental Charge	See Sheet No. 8.030.1		

(Continued on Sheet No. 8.761)

160001 Hearing Exhibits 00371

TRANSFORMATION RIDER - TR

AVAILABLE:

In all territory served.

APPLICATION:

In conjunction with any commercial or industrial rate schedule specifying delivery of service at any available standard voltage when Customer takes service from available primary lines of 2400 volts or higher at a single point of delivery.

MONTHLY CREDIT:

The Company, at its option, will either provide and maintain transformation facilities equivalent to the capacity that would be provided if the load were served at a secondary voltage from transformers at one location or, when Customer furnishes transformers, the Company will allow a monthly credit of $0.15 per kW of Billing Demand. Any transformer capacity required by the Customer in excess of that provided by the Company hereunder may be rented by the Customer at the Company's standard rental charge.

The credit will be deducted from the monthly bill as computed in accordance with the provisions of the Monthly Rate section of the applicable Rate Schedule before application of any discounts or adjustments. No monthly bill will be rendered for an amount less than the minimum monthly bill called for by the Agreement for Service.

SPECIAL CONDITIONS:

The Company may change its primary voltage at any time after reasonable advance notice to any Customer receiving credit hereunder and affected by such change, and the Customer then has the option of changing its system so as to receive service at the new line voltage or of accepting service (without the benefit of this rider) through transformers supplied by the Company.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

SEASONAL DEMAND – TIME OF USE RIDER – SDTR
(OPTIONAL)

RIDER: SDTR

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW. This is an optional rate available to customers otherwise served under the GSD-1 GSDT-1, GSLD-1, GSLDT-1, GSLD-2 or GSLDT-2 Rate Schedules.

SERVICE:
Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:
OPTION A: Non-Seasonal Standard Rate

Annual Maximum Demand	SDTR-1 21-499 kW	SDTR-2 500-1,999 kW	SDTR-3 2,000 kW or greater
Customer Charge:	$25.00	$75.00	$225.00
Demand Charges:			
Seasonal On-peak Demand Charge Per kW of Seasonal On-peak Demand	$10.10	$11.40	$12.00
Non-Seasonal Demand Charge Per kW of Non- Seasonal Maximum Demand	$8.90	$10.80	$11.18
Capacity Payment Charge:	See Sheet No. 8.030		
Conservation Charge:	See Sheet No. 8.030		
Energy Charges:			
Base Seasonal On-Peak Per kWh of Seasonal On-Peak Energy	8.093 ¢	5.648 ¢	4.538 ¢
Base Seasonal Off-Peak Per kWh of Seasonal Off-Peak Energy	1.459 ¢	1.143 ¢	1.112 ¢
Base Non-Seasonal Energy Charge Per kWh of Non-Seasonal Energy	2.035 ¢	1.585 ¢	1.427 ¢
Environmental Charge:	See Sheet No. 8.030		
Additional Charges:			
Fuel Charge:	See Sheet No. 8.030		
Storm Charge:	See Sheet No. 8.040		
Franchise Fee:	See Sheet No. 8.031		
Tax Clause:	See Sheet No. 8.031		

(Continued from Sheet No. 8.830)

OPTION B: Non-Seasonal Time of Use Rate

Annual Maximum Demand	SDTR-1 21-499 kW	SDTR-2 500-1,999 kW	SDTR-3 2,000 kW or greater
Customer Charge:	$25.00	$75.00	$225.00
Demand Charges:			
Seasonal On-peak Demand Charge Per kW of Seasonal On-peak Demand	$10.10	$11.40	$12.00
Non-Seasonal Demand Charge Per kW of Non- Seasonal Peak Demand	$8.90	$10.80	$11.18
Capacity Payment Charge	See Sheet No. 8.030		
Conservation Charge	See Sheet No. 8.030		
Energy Charges:			
Base Seasonal On-Peak Per kWh of Seasonal On-Peak Energy	8.093 ¢	5.648 ¢	4.538 ¢
Base Seasonal Off-Peak Per kWh of Seasonal Off-Peak Energy	1.459 ¢	1.143 ¢	1.112 ¢
Base Non-Seasonal On-Peak Per kWh of Non-Seasonal On-Peak Energy	4.622 ¢	3.384 ¢	3.113 ¢
Base Non-Seasonal Off-Peak Per kWh of Non-Seasonal Off-Peak Energy	1.459 ¢	1.143 ¢	1.112 ¢
Environmental Charge	See Sheet No. 8.030		
Additional Charges:			
Fuel Charge	See Sheet No. 8.030		
Storm Charge	See Sheet No. 8.040		
Franchise Fee	See Sheet No. 8.031		
Tax Clause	See Sheet No. 8.031		

Minimum Charge: The Customer Charge plus the currently effective Demand Charges.

NON-SEASONAL RATING PERIODS (OPTION B only):

Non-Seasonal On-Peak Period:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through May 31 and October 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day.

Non-Seasonal Off-Peak Period:

All other hours.

(Continued On Sheet No. 8.832)

160001 Hearing Exhibits 00374

SURETY BOND

KNOW ALL PERSONS BY THESE PRESENTS:

THAT WE,_____ as Principal at (mailing address)_____,

and_____, a surety company at (mailing address) _____ authorized to do business in the State of Florida, as Surety are held and firmly bound to Florida Power & Light Company, a corporation organized and existing under the laws of the State of Florida, its successors and assigns, in the amount of $_____, lawful money of the United States of America for the payment of which the Principal and Surety, their heirs, executors, administrators, successors and assigns are hereby jointly and severally bound.

WHEREAS, pursuant to its authorized General Rules and Regulations for Electric Service, Florida Power & Light Company requires the Principal to establish credit for prompt payment of its monthly utility bills, and Principal and Florida Power & Light Company agree that Principal may do so by furnishing this surety bond for prompt payment of the monthly utility bills to be rendered by Florida Power & Light Company;

NOW THEREFORE, the condition of this obligation is such that if the Principal shall promptly pay all amounts which may be due by Principal to Florida Power & Light Company for utility services in the Principal's name at any or all premises, then this obligation shall be null and void; otherwise it shall remain in full force and effect.

PROVIDED FURTHER, that Principal and Surety jointly and severally agree that if at any time Principal's payment, or any part thereof, of Principal's obligations to Florida Power & Light Company is rescinded or must otherwise be restored or returned for any reason whatsoever (Including, but not limited to, insolvency, bankruptcy or reorganization), then the Surety obligation shall, to the extent of the payment rescinded or returned, be deemed to have continued in existence, notwithstanding such previous payment, and the Surety obligation shall continue to be effective or be reinstated, as the case may be, as to such payment, all as though such previous payment had never been made;

PROVIDED FURTHER, that regardless of the number of years this bond shall continue or be continued in force and of the number of premiums which shall be payable or paid, the Surety shall not be liable thereunder for a larger amount, in the aggregate, than the amount of this bond, unless suit must be brought for enforcement of the within obligations in which case the Surety will also be liable for all costs in connection therewith and reasonable attorneys' fees, including costs of and fees for appeals; and

PROVIDED FURTHER, that should the Surety so elect, this bond may be canceled by the Surety as to subsequent liability by giving thirty (30) days notice in writing by certified mail-return receipt requested to Florida Power & Light Company at P.O. Box 025209, Miami, Florida 33102-5209. The notice of cancellation shall not be effective unless it includes the Principal's name and "Master Account Number_____" written thereon.

Signed, sealed and dated this_____ day of_____.

[ ]

Signature format in this section will vary depending on type of legal entity
(Corporation, Partnership, Joint Venture, Sole Proprietor)

[ ]

Corporate	Surety_____	Notary
Seal	By_____	Seal
	(Designated in attached Power of Attorney, If not Florida Resident, countersigned below.)	
of SURETY		(Surety)

(Continued on Sheet No. 9.441)

160001 Hearing Exhibits 00375

CONTRACT PROVISIONS - VARIOUS

FACILITIES RENTAL SERVICE. When required by the Customer, the Company may, at its option, provide and maintain transformers and other facilities which are required by the Customer beyond the Point of Delivery or which are needed because the Customer requires unusual facilities due to the nature of his equipment. The Company shall not be required to install facilities if they cannot be economically justified. The charge for this service is based on the agreed installed cost of such facilities.

Upon mutual agreement between the Company and the Customer, the Customer may elect to make either a lump sum payment or pay a monthly charge. The monthly charge shall recover 21% per year of the agreed installed cost of such facilities. Those Customers electing to make a lump sum payment shall have the option of either including the cost of maintenance in a lump sum, or paying a separate monthly maintenance charge. If the Customer elects to pay for the maintenance in the lump sum, the amount will be based on the estimated cost of maintenance over the term of the contract.

Those customers renting electric facilities from the Company, subsequent to a change in the Facilities Rental Service charge and upon mutual agreement, may continue to receive electrical service under one of the following options: 1) continue the rental facilities by payment based on the revised charge, 2) purchase such facilities from the Company as mutually agreed upon, 3) purchase or lease the facilities from another source, or 4) redesign its operation to receive standard electric service from the Company.

MUNICIPAL FIRE PUMP DEMANDS. Demands caused by the operation of municipal fire pumps are waived whenever the pumps are used in emergencies for the purpose of extinguishing fires, or when the pumps are operated for testing purposes provided the time of the test is mutually agreed upon beforehand.

SECONDARY METERING ADJUSTMENT. Where the rate schedule provides for delivery of service at primary voltage and it is necessary or desirable to meter at secondary voltage, the readings of Company's meters are corrected to conform to the voltage of delivery by adding 2% to the demand indications and 3% to the kwh registrations.

UNMETERED SERVICE. In some circumstances the installation of a meter is difficult, impracticable, or not warranted by the nature of the load to be served. In such cases the Company may elect to estimate the demand and energy requirements and calculate the bill on these estimated values.

NET METERING OF CUSTOMER-OWNED RENEWABLE GENERATION. For Customers with renewable generation equipment up to a maximum of 2 MW that have executed an Interconnection Agreement for Customer-Owned Renewable Generation with the Company, the following billing parameters will apply.

The customer will be charged for electricity used in excess of the generation supplied by customer-owned renewable generation in accordance with the Company's normal billing practices. If any excess customer-owned renewable generation is delivered to the Company's electric grid during the course of a billing cycle, it will be credited to the customer's energy consumption for the next month's billing cycle.

All excess energy credits will be accumulated and be used to offset the customer's energy usage in subsequent months for a period of not more than twelve months. In the last billing cycle month of each calendar year, any unused credits for excess kWh generated will be credited to the next month's billing cycle using the average annual rate based on the Company's COG-1, As-Available Energy Tariff. In the event a customer closes the account, any of the customer's unused credits for excess kWh generated will be paid to the customer at an average annual rate based on the Company's COG-1, As-Available Energy Tariff.

Regardless of whether excess energy is delivered to the Company's electric grid, the customer will be required to pay the greater of 1. the minimum charge as stated in their applicable rate schedule, or 2. the applicable customer charge plus the applicable demand charge for the maximum measured demand during the billing period in accordance with the provisions of their applicable rate schedule. Any charges for electricity used by the customer in excess of the generation supplied by customer-owned renewable generation will be in accordance with their applicable rate schedule. The Customer's eligibility to take service under time of use rates is not affected by this provision. Additionally, the customer, at their sole discretion, may choose to take service under the Company's standby or supplemental service rate, if available.

Appendix A

Distribution Substation Facilities
Monthly Rental and Termination Factors

The Monthly Rental Factor to be applied to the in-place value of the Distribution Substation Facilities as identified in the Long-Term Rental Agreement is as follows:

	Monthly Rental Factor
Distribution Substation Facilities	1.33%

Termination Fee for Initial 20 Year Period

If the Long-Term Rental Agreement for Distribution Substation Facilities is terminated by Customer during the Initial Term, Customer shall pay to Company a Termination Fee, such fee shall be computed by applying the following Termination Factors to the in-place value of the Facilities based on the year in which the Agreement is terminated:

Year Agreement Is Terminated	Termination Factors %	Year Agreement Is Terminated	Termination Factors %	Year Agreement Is Terminated	Termination Factors %
1	3.33	8	11.11	15	6.00
2	5.98	9	10.83	16	4.87
3	7.97	10	10.36	17	3.70
4	9.40	11	9.73	18	2.49
5	10.36	12	8.95	19	1.25
6	10.92	13	8.06	20	0.00
7	11.15	14	7.07		

Termination Fee for Subsequent Extension Periods

If the Long-Term Rental Agreement for Distribution Substation Facilities is terminated by Customer during an Extension, Customer shall pay to Company a Termination Fee, such fee shall be computed based on the net present value of the remaining payments under the extension period by applying the Termination Factor based on the month terminated to the monthly rental payment amount.

Month Terminated	Termination Factor	Month Terminated	Termination Factor	Month Terminated	Termination Factor	Month Terminated	Termination Factor
1	49.992	16	39.231	31	27.386	46	14.349
2	49.307	17	38.476	32	26.555	47	13.435
3	48.616	18	37.716	33	25.719	48	12.514
4	47.922	19	36.952	34	24.878	49	11.588
5	47.223	20	36.182	35	24.031	50	10.656
6	46.519	21	35.408	36	23.178	51	9.718
7	45.811	22	34.629	37	22.321	52	8.774
8	45.099	23	33.844	38	21.457	53	7.824
9	44.381	24	33.055	39	20.589	54	6.868
10	43.660	25	32.261	40	19.714	55	5.905
11	42.933	26	31.461	41	18.834	56	4.937
12	42.202	27	30.656	42	17.949	57	3.962
13	41.466	28	29.847	43	17.057	58	2.981
14	40.726	29	29.032	44	16.160	59	1.994
15	39.981	30	28.211	45	15.258	60	1.000

Issued By: S. E. Romig, Director, Rates and Tariffs
Effective: January 1, 2017

EXHIBIT C

2018 TARIFFS

PROPOSED AND LEGISLATIVE

SERVICE CHARGES

A $25.00 service charge will be made for an initial connection.

A $13.00 Reconnection Charge will be made for the reconnection of service after disconnection for nonpayment or violation of a rule or regulation.

A $12.00 service charge will be made for the connection of an existing account.

A Returned Payment Charge as allowed by Florida Statute 68.065 shall apply for each check or draft dishonored by the bank upon which it is drawn. Termination of service shall not be made for failure to pay the Returned Payment Charge.

Charges for services due and rendered which are unpaid as of the past due date are subject to a Late Payment Charge of the greater of $5.00 or 1.5% applied to any past due unpaid balance of all accounts, except the accounts of federal, state, and local governmental entities, agencies, and instrumentalities. A Late Payment Charge shall be applied to the accounts of federal, state, and local governmental entities, agencies, and instrumentalities at a rate no greater than allowed, and in a manner permitted, by applicable law.

A $~~49.00~~48.00 Field Collection Charge will be added to a customer's bill for electric service when a field visit is made and payment is collected on a delinquent account. If service is disconnected, or a current receipt of payment is shown at the time of the field visit, this charge will not be applied.

FPL may waive the Reconnection Charge, Returned Payment Charge, Late Payment Charge and Field Collection Charge for Customers affected by natural disasters or during periods of declared emergencies or once in any twelve (12) month period for any Customer who would otherwise have had a satisfactory payment record (as defined in 25-6.097(2) F.A.C.), upon acceptance by FPL of a reasonable explanation justifying a waiver. In addition, FPL may waive the charge for connection of an existing account and the charge for an initial connection for new or existing Customers affected by natural disasters or during periods of declared emergencies.

CONSERVATION INSPECTIONS AND SERVICES

Residential Dwelling Units:
A charge of $15.00 will be made for a computerized energy analysis in which a comprehensive on-site evaluation of the residence is performed.

Commercial/Industrial:
There is no charge for conservation inspections and services (Business Energy Services).

TEMPORARY/CONSTRUCTION SERVICE

APPLICATION:

For temporary electric service to installations such as fairs, exhibitions, construction projects, displays and similar installations.

SERVICE:

Single phase or three phase, 60 hertz at the available standard secondary distribution voltage. This service is available only when the Company has existing capacity in lines, transformers and other equipment at the requested point of delivery. The Customer's service entrance electrical cable shall not exceed 200 Amp capacity.

CHARGE:

The non-refundable charge must be paid in advance of installation of such facilities which shall include service and metering equipment.

Installing and removing overhead service and meter	$~~367.00~~376.00
Connecting and disconnecting Customer's service cable to Company's direct-buried underground facilities including installation and removal of meter	$~~209.00~~215.00

MONTHLY RATE:

This temporary service shall be billed under the appropriate rate schedule applicable to commercial and industrial type installations.

SPECIAL CONDITIONS:

If specific electrical service other than that stated above is required, the Company, at the Customer's request, will provide such service based on the estimated cost of labor for installing and removing such additional electrical equipment. This estimated cost will be payable in advance to the Company and subject to adjustment after removal of the required facilities. All Temporary/Construction services shall be subject to all of the applicable Rules, Regulations and Tariff charges of the Company, including Service Charges.

GENERAL SERVICE - NON DEMAND

RATE SCHEDULE: GS-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose with a demand of 20 kW or less.

SERVICE:

Single phase, 60 hertz and at any available standard distribution voltage. Three phase service will be provided without additional charge unless the Company's line extension policy is applicable thereto. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$10.00
Non-Fuel Energy Charges:	
Base Energy Charge	~~5.439~~5.664 ¢ per kWh
Conservation Charge	See Sheet No. 8.030
Capacity Payment Charge	See Sheet No. 8.030
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
General Service Load Management Program (if applicable)	See Sheet No. 8.109
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum:	$10.00
Non-Metered Accounts:	A Customer Charge of $5.00 will apply to those accounts which are billed on an estimated basis and, at the Company's option, do not have an installed meter for measuring electric service. The minimum charge shall be $5.00.

SPECIAL PROVISIONS:

Energy used by commonly owned facilities of condominium, cooperative and homeowners' associations may qualify for the residential rate schedule as set forth on Sheet No. 8.211, Rider CU.

TERM OF SERVICE:

Not less than one (1) billing period.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE - NON DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: GST-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose with a demand of 20 kW or less. This is an optional rate available to General Service - Non Demand customers upon request subject to availability of meters.

SERVICE:

Single phase, 60 hertz and at any available standard distribution voltage. Three phase service will be provided without additional charge unless the Company's line extension policy is applicable thereto. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$10.00	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~10.038~~10.459 ¢ per kWh	~~3.441~~3.581 ¢ per kWh
Conservation Charge	See Sheet No. 8.030	
Capacity Payment Charge	See Sheet No. 8.030	
Environmental Charge	See Sheet No. 8.030	

Additional Charges:

General Service Load Management Program (if applicable)	See Sheet No. 8.109
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: $10.00

Initial service under this rate schedule shall begin on the first scheduled meter reading date following the installation of the time of use meter.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to l0 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.104)

160001 Hearing Exhibits 00383

GENERAL SERVICE DEMAND

RATE SCHEDULE: GSD-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW and less than 500 kW. Customers with a Demand of 20 kW or less may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 21 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$25.00
Demand Charges:	
Base Demand Charge	$~~9.20~~9.40 per kW
Capacity Payment Charge	See Sheet No. 8.030, per kW
Conservation Charge	See Sheet No. 8.030, per kW
Non-Fuel Energy Charges:	
Base Energy Charge	~~2.035~~2.096 ¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of 20 kW or less who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 21 kW times the Base Demand Charge; therefore the minimum charge is $~~218.20~~222.40.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's thermal type meter or, at the Company's option, integrating type meter for the 30-minute period of Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: GSDT-1

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW and less than 500 kW. Customers with Demands of less than 21 kW may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 21 kW. This is an optional rate available to General Service Demand customers upon request subject to availability of meters.

SERVICE:
Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$25.00
Demand Charges:	
Base Demand Charge	$~~9.20~~9.40 per kW of Demand occurring during the On-Peak period.
Capacity Payment Charge	See Sheet No. 8.030, per kW of Demand occurring during the On-Peak period.
Conservation Charge	See Sheet No. 8.030, per kW of Demand occurring during the On-Peak period.

Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~4.142~~4.275 ¢ per kWh	~~1.102~~1.131 ¢ per kWh
Environmental Charge	See Sheet No. 8.030	

Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 21 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 21 kW times the Base Demand Charge, therefore the minimum charge is $~~218.20.~~222.40.

RATING PERIODS:
On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.108)

160001 Hearing Exhibits 00385

GENERAL SERVICE CONSTANT USAGE

RATE SCHEDULE: GSCU-1

AVAILABLE:

In all territory served.

APPLICATION:

Available to General Service - Non Demand customers that maintain a relatively constant kWh usage, and a demand of 20 kW or less. Eligibility is restricted to General Service customers whose Maximum kWh Per Service Day, over the current and prior 23 months, is within 5% of their average monthly kWh per service days calculated over the same 24-month period. Customers under this Rate Schedule shall enter into a General Service Constant Use Agreement. This is an optional Rate Schedule available to General Service customers upon request.

SERVICE:

Single phase, 60 hertz and at any available standard distribution voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$14.00
Non-Fuel Energy Charges:	
Base Energy Charge*	~~3.507~~3.515 ¢ per Constant Usage kWh
Conservation Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Capacity Payment Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Environmental Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Additional Charges:	
Fuel Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Storm Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

* The fuel, storm and non-fuel energy charges will be assessed on the Constant Usage kWh

TERM OF SERVICE:

Initial term of service under this rate schedule shall be not less than one (1) billing period, unless there is a termination of service due to a Customer's violation of the General Service Constant Usage Agreement. Upon the Customer's violation of any of the terms of the General Service Constant Usage Agreement, service under this Rate Schedule will be terminated immediately. To terminate service, either party must provide thirty (30) days written notice to the other party prior to the desired termination date. Absent such notice, the term of service shall automatically be extended another billing period. In addition, if service under this Rate Schedule is terminated by either the Customer or the Company, the account may not resume service under this Rate Schedule for a period of at least one (1) year.

DEFINITIONS:

kWh Per Service Day – the total kWh in billing month divided by the number of days in the billing month

Maximum kWh Per Service Day - the highest kWh Per Service Day experienced over the current and prior 23 month billing periods

Constant Usage kWh – the Maximum kWh Per Service Day multiplied by the number of service days in the current billing period

(Continued on Sheet 8.123)

160001 Hearing Exhibits 00386

RESIDENTIAL SERVICE

RATE SCHEDULE: RS-1

AVAILABLE:

In all territory served.

APPLICATION:

For service for all domestic purposes in individually metered dwelling units and in duplexes and triplexes, including the separately-metered non-commercial facilities of a residential Customer (i.e., garages, water pumps, etc.). Also for service to commonly-owned facilities of condominium, cooperative and homeowners' associations as set forth on Sheet No. 8.211, Rider CU.

SERVICE:

Single phase, 60 hertz at available standard distribution voltage. Three phase service may be furnished but only under special arrangements. All residential service required on the premises by Customer shall be supplied through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$7.87
Non-Fuel Charges:	
Base Energy Charge:	
First 1,000 kWh	~~5.562~~5.801 ¢ per kWh
All additional kWh	~~6.562~~6.801 ¢ per kWh
Conservation Charge	See Sheet No. 8.030
Capacity Payment Charge	See Sheet No. 8.030
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Residential Load Control Program (if applicable)	See Sheet No. 8.217
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum:	$7.87

TERM OF SERVICE:

Not less than one (1) billing period.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective: January 1, ~~2017~~2018

RESIDENTIAL TIME OF USE RIDER – RTR-1
(OPTIONAL)

RIDER: RTR-1

AVAILABLE:
In all territory served.

APPLICATION:

For service for all domestic purposes in individually metered dwelling units and in duplexes and triplexes, including the separately-metered non-commercial facilities of a residential Customer (i.e., garages, water pumps, etc.). Also for service to commonly-owned facilities of condominium, cooperative and homeowners' associations as set forth on Sheet No. 8.211, Rider CU. This is an optional rider available to residential customers served under the RS-1 Rate Schedule subject to availability of meters. Customers taking service under RTR-1 are not eligible for service under Rate Schedule RLP.

SERVICE:
Single phase, 60 hertz at available standard distribution voltage. Three phase may be supplied but only under special arrangements. All residential service required on the premises by Customer shall be supplied through one meter. Resale of service is not permitted hereunder.

Initial service under this rate schedule shall begin on the first scheduled meter reading date following the installation of the time of use meter. The Customer's first bill will reflect the lesser of the charges under Rate Schedule RS-1 or RTR-1.

MONTHLY RATE:

Except for the Customer Charge, all rates and charges under Rate Schedule RS-1 shall apply. In addition, the RTR-1 Customer Charge, the RTR-1 Base Energy and Fuel Charges and Credits applicable to on and off peak usage shall apply.

Customer Charge:	$7.87	
Base Energy Charges/Credits:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~9.937~~10.349 ¢ per kWh	(~~4.420~~4.604) ¢ per kWh
Additional Charges/Credits:		
RTR Fuel Charge/Credit	See Sheet No. 8.030	
Minimum:	$7.87	

RATING PERIODS:
On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.204)

160001 Hearing Exhibits 00388

GENERAL SERVICE LARGE DEMAND

RATE SCHEDULE: GSLD-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer with a measured demand of 500 kW and less than 2,000 kW. Customers with demands of less than 500 kW may enter an agreement for service under this Rate Schedule based on a Demand Charge for a minimum of 500 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$75.00
Demand Charges:	
Base Demand Charge	$~~11.00~~11.50 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	~~1.585~~1.657 ¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charges	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is $~~5,575.~~5,825.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's thermal type meter or, at the Company's option, integrating type meter for the 30-minute period of Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE LARGE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE GSLDT-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer with a measured demand of 500 kW and less than 2,000 kW. Customers with demands of less than 500 kW may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 500 kW. This is an optional rate available to General Service Large Demand customers upon request subject to availability of meters.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$75.00	
Demand Charges:		
Base Demand Charge	$~~11.00~~11.50 per kW of Demand occurring during the On-Peak period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~2.597~~2.712 ¢ per kWh	~~1.143~~1.196 ¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is $~~5,575.~~5,825.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.321)

160001 Hearing Exhibits 00390

CURTAILABLE SERVICE
(OPTIONAL)

RATE SCHEDULE: CS-1

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-1 (500 kW - 1,999 kW) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. Customers with demands of at least 200 kW but less than 500 kW may enter an agreement for service under this Rate Schedule based on a Demand Charge for a minimum of 500 kW.

SERVICE:
Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$100.00
Demand Charges:	
Base Demand Charge	$~~11.00~~11.50 per kW of Demand.
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	~~1.585~~1.657 ¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is $~~5,600.00~~5,850.

CURTAILMENT CREDITS:
A monthly credit of ($1.93) per kW is allowed based on the current Non-Firm Demand. The Customer has the option to revise the Firm Demand once during the initial twelve (12) month period. Thereafter, subject to the Term of Service and/or the Provisions for Early Termination, a change to the Firm Demand may be made provided that the revision does not decrease the total amount of Non-Firm Demand during the lesser of: (i) the average of the previous 12 months; or (ii) the average of the number of billing months under this Rate Schedule.

CHARGES FOR NON-COMPLIANCE OF CURTAILMENT DEMAND:
If the Customer records a higher Demand during the current Curtailment Period than the Firm Demand, the Customer will be:

1. Rebilled at $1.93/kW for the prior 36 months or the number of months since the prior Curtailment Period, whichever is less, and
2. Billed a penalty charge of $4.16 kW for the current month.

The kW used for both the rebilling and penalty charge calculations is determined by taking the difference between the maximum Demand during the current Curtailment Period and the Firm Demand for a Curtailment Period.

(Continued on Sheet No. 8.331)

160001 Hearing Exhibits 00391

CURTAILABLE SERVICE - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: CST-1

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-1 (500 kW - 1,999 kW) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. This is an optional Rate Schedule available to Curtailable General Service Customers upon request. Customers with demands of at least 200 kW but less than 500 kW may enter an agreement for service under this Rate Schedule based on a Demand Charge for a minimum of 500 kW

SERVICE:

Single or three phase, 60 hertz and at any available distribution standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$100.00	
Demand Charges:		
Base Demand Charge	$~~11.00~~11.50 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~2.597~~2.712 ¢ per kWh	~~1.143~~1.196 ¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is $~~5,600.00.~~5,850.

RATING PERIODS:

On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.341)

160001 Hearing Exhibits 00392

GENERAL SERVICE LARGE DEMAND

RATE SCHEDULE: GSLD-2

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer with a measured demand of 2,000 kW or more. Customers with demands of less than 2,000 kW may enter an agreement for service under this schedule based on a demand charge for a minimum of 2,000 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$225.00
Demand Charges:	
Base Demand Charge	$~~11.40~~12.00 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	~~1.427~~1.493 ¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a demand of less than 2,000 kW who enter an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is $~~23,025.~~24,225.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's metering equipment, for the 30-minute period of the Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE LARGE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: GSLDT-2

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer who has established a measured demand of 2,000 kW or more. Customers with demands of less than 2,000 kW may enter an agreement for service under this schedule based on a demand charge for a minimum of 2,000 kW.

SERVICE:

Three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$225.00	
Demand Charges:		
Base Demand Charge	$~~11.40~~12.00 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~2.227~~2.316 ¢ per kWh	~~1.112~~1.169 ¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a demand of less than 2,000 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is $~~23,025.~~24,225.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.421)

160001 Hearing Exhibits 00394

HIGH LOAD FACTOR – TIME OF USE
(OPTIONAL)

RATE SCHEDULE: HLFT

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW. This is an optional rate schedule available to customers otherwise served under the GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, or GSLDT-2 Rate Schedules.

SERVICE:
Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Annual Maximum Demand	HLFT-1 21-499 kW	HLFT-2 500-1,999 kW	HLFT-3 2,000 kW or greater
Customer Charge:	$25.00	$75.00	$225.00
Demand Charges:			
On-peak Demand Charge	$~~10.80~~11.10	$~~11.60~~12.10	
$~~11.60~~12.20			
Maximum Demand Charge	$2.30	$~~2.50~~2.60	$~~2.50~~2.60
Capacity Payment Charge	See Sheet No. 8.030, per kW of On-Peak Demand		
Conservation Charge	See Sheet No. 8.030, per kW of On-Peak Demand		
Non-Fuel Energy Charges:			
On-Peak Period per kWh	~~1.738~~1.813 ¢	~~1.003~~1.071 ¢	
~~0.903~~0.951 ¢			
Off-Peak Period per kWh	~~1.102~~1.131 ¢	~~0.977~~1.023 ¢	~~0.898~~0.944 ¢
Environmental Charge	See Sheet No. 8.030		
Additional Charges			
Fuel Charge	See Sheet No. 8.030		
Storm Charge	See Sheet No. 8.040		
Franchise Fee	See Sheet No. 8.031		
Tax Clause	See Sheet No. 8.031		

Minimum Charge: The Customer Charge plus the currently effective Demand Charges.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.426)

160001 Hearing Exhibits 00395

CURTAILABLE SERVICE
(OPTIONAL)

RATE SCHEDULE: CS-2

AVAILABLE:

In all territory served.

APPLICATION:

For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-2 (2,000 kW and above) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. Customers with demands of less than 2,000 kW may enter an Agreement for service under this schedule based on a Demand Charge for a minimum of 2,000 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$250.00
Demand Charges:	
Base Demand Charge	$~~11.40~~12.00 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	~~1.427~~1.493 ¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 2,000 kW who enter an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is $~~23,050.~~24,250.

CURTAILMENT CREDITS:

A monthly credit of ($1.93) per kW is allowed based on the current Non-Firm Demand. The Customer has the option to revise the Firm Demand once during the initial twelve (12) month period. Thereafter, subject to the Term of Service and/or the Provisions for Early Termination, a change to the Firm Demand may be made provided that the revision does not decrease the total amount of Non-Firm Demand during the lesser of: (i) the average of the previous 12 months; or (ii) the average of the number of billing months under this Rate Schedule.

CHARGES FOR NON-COMPLIANCE OF CURTAILMENT DEMAND:

If the Customer records a higher Demand during the current period than the Firm Demand, then the Customer will be:

1. Rebilled at $1.93 /kW for the prior 36 months or the number of months since the prior Curtailment Period, whichever is less, and
2. Billed a penalty charge of $4.16 /kW for the current month.

The kW used for both the rebilling and penalty charge calculations is determined by taking the difference between the maximum Demand during the current Curtailment Period and the contracted Firm Demand for a Curtailment Period.

(Continued on Sheet No. 8.433)

160001 Hearing Exhibits 00396

CURTAILABLE SERVICE - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: CST-2

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLDT-2 (2,000 kW and above) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. Customers with demands of less than 2,000 kW may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 2,000 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$250.00	
Demand Charges:		
Base Demand Charge	$~~11.40~~12.00 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~2.227~~2.316 ¢ per kWh	~~1.112~~1.169 ¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 2,000 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is $~~23,050.~~24,250.

RATING PERIODS:

On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.441)

160001 Hearing Exhibits 00397

CURTAILABLE SERVICE - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: CST-3

AVAILABLE:

In all territory served.

APPLICATION:

For any commercial or industrial Customer who qualifies for Rate Schedule GSLDT-3 and will curtail this Demand by 200 kW or more upon request of the Company from time to time.

SERVICE:

Three phase, 60 hertz at the available transmission voltage of 69 kV or higher. The Customer will provide and maintain all transformers and related facilities necessary for handling and utilizing the power and energy delivered hereunder. All service required by the Customer at each separate point of delivery served hereunder shall be furnished through one meter at, or compensated to, the available transmission voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$2,025.00	
Demand Charges:		
Base Demand Charge	$9.30 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030.1	
Conservation Charge	See Sheet No. 8.030.1	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~1.217~~1.227 ¢ per kWh	~~1.016~~1.019 ¢ per kWh
Environmental Charge	See Sheet No. 8.030.1	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030.1	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.543)

160001 Hearing Exhibits 00398

CURTAILABLE SERVICE
(OPTIONAL)

RATE SCHEDULE: CS-3

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-3 and will curtail this Demand by 200 kW or more upon request of the Company from time to time.

SERVICE:
Three phase, 60 hertz at the available transmission voltage of 69 kV or higher. The Customer will provide and maintain all transformers and related facilities necessary for handling and utilizing the power and energy delivered hereunder. All service required by the Customer at each separate point of delivery served hereunder shall be furnished through one meter at, or compensated to, the available transmission voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$2,025.00
Demand Charges:	
Base Demand Charge	$9.30 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030.1
Conservation Charge	See Sheet No. 8.030.1
Non-Fuel Energy Charges:	
Base Energy Charge	~~1.069~~1.074 ¢ per kWh
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum Charge: The Customer Charge plus the charge for the currently effective Base Demand.

CURTAILMENT CREDITS:
A monthly credit of ($1.93) per kW is allowed based on the current Non-Firm Demand. The Customer has the option to revise the Firm Demand once during the initial twelve (12) month period. Thereafter, subject to the Term of Service and/or the Provisions for Early Termination, a change to the Firm Demand may be made provided that the revision does not decrease the total amount of Non-Firm Demand during the lesser of: (i) the average of the previous 12 months; or (ii) the average of the number of billing months under this Rate Schedule.

CHARGES FOR NON-COMPLIANCE OF CURTAILMENT DEMAND:

If the Customer records a higher Demand during the current Curtailment Period than the Firm Demand, then the Customer will be:

1. Rebilled at $1.93 /kW for the prior 36 months or the number of months since the prior Curtailment Period, whichever is less, and
2. Billed a penalty charge of $4.16 /kW for the current month.

The kW used for both the rebilling and penalty charge calculations is determined by taking the difference between the maximum Demand during the current Curtailment Period and the Firm Demand for a Curtailment Period.

(Continued on Sheet No. 8.546)

160001 Hearing Exhibits 00399

GENERAL SERVICE LARGE DEMAND

RATE SCHEDULE: GSLD-3

AVAILABLE:

In all territory served.

APPLICATION:

For service required for commercial or industrial lighting, power and any other purpose to any Customer who has service supplied at a transmission voltage of 69 kV or higher.

SERVICE:

Three phase, 60 hertz at the available transmission voltage of 69 kV or higher. The Customer will provide and maintain all transformers and related facilities necessary for handling and utilizing the power and energy delivered hereunder. All service required by the Customer at each separate point of delivery served hereunder shall be furnished through one meter at, or compensated to, the available transmission voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$2,000.00
Demand Charges:	
Base Demand Charge	$9.30 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030.1
Conservation Charge	See Sheet No. 8.030.1
Non-Fuel Energy Charges:	
Base Energy Charge	~~1.069~~1.074¢ per kWh
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's metering equipment for the 30-minute period of the Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective: January 1, ~~2017~~2018

GENERAL SERVICE LARGE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: GSLDT-3

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose to any Customer who has service supplied at a transmission voltage of 69 kV or higher.

SERVICE:

Three phase, 60 hertz at the available transmission voltage of 69 kV or higher. The Customer will provide and maintain all transformers and related facilities necessary for handling and utilizing the power and energy delivered hereunder. All service required by the Customer at each separate point of delivery served hereunder shall be furnished through one meter at, or compensated to, the available transmission voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$2,000.00	
Demand Charges:		
Base Demand Charge	$9.30 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030.1	
Conservation Charge	See Sheet No. 8.030.1	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~1.217~~1.227 ¢ per kWh	~~1.016~~1.019 ¢ per kWh
Environmental Charge	See Sheet No. 8.030.1	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030.1	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand.

RATING PERIODS:

On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.553)

160001 Hearing Exhibits 00401

SPORTS FIELD SERVICE
(Closed Schedule)

RATE SCHEDULE: OS-2

AVAILABLE:

In all territory served.

APPLICATION:

This is a transitional rate available to municipal, county and school board accounts for the operation of a football, baseball or other playground, or civic or community auditorium, when all such service is taken at the available primary distribution voltage at a single point of delivery and measured through one meter, and who were active as of October 4, 1981. Customer may also elect to receive service from other appropriate rate schedules.

LIMITATION OF SERVICE:

Offices, concessions, businesses or space occupied by tenants, other than areas directly related to the operations above specified, are excluded hereunder and shall be separately served by the Company at utilization voltage. Not applicable when Rider TR is used.

MONTHLY RATE:

Customer Charge:	$125.00
Non-Fuel Energy Charges:	
Base Energy Charge	~~7.455~~7.864 ¢ per kWh
Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum Charge:	$125.00

TERM OF SERVICE:

Pending termination by Florida Public Service Commission Order.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

METROPOLITAN TRANSIT SERVICE

RATE SCHEDULE: MET

AVAILABLE:

For electric service to Metropolitan Miami-Dade County Electric Transit System (METRORAIL) at each point of delivery required for the operation of an electric transit system on continuous and contiguous rights-of-way.

APPLICATION:

Service to be supplied will be three phase, 60 hertz and at the standard primary distribution voltage of 13,200 volts. All service required by Customer at each separate point of delivery served hereunder shall be furnished through one meter reflecting delivery at primary voltage. Resale of service is not permitted hereunder. Rider TR or a voltage discount is not applicable.

MONTHLY RATE:

Customer Charge:	$~~550.00~~600.00
Demand Charges:	
Base Demand Charge	$12.70 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030.1
Conservation Charge	See Sheet No. 8.030.1
Non-Fuel Energy Charges:	
Base Energy Charge	~~1.692~~1.693 ¢ per kWh
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand.

DEMAND:

The billing Demand is the kW, at each point of delivery, to the nearest whole kW, as determined from the Company's recording type metering equipment, for the period coincident with the 30-minute period of the electric rail transit system's greatest use supplied by the Company during the month adjusted for power factor.

BILLING:

Each point of delivery shall be separately billed according to the monthly charges as stated herein. All billing units related to charges under this rate schedule shall be determined from metering data on a monthly basis and determined for each point of delivery on the same monthly billing cycle day.

TERMS OF SERVICE

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective: January 1, ~~2017~~2018

(Continued from Sheet No. 8.650)

MONTHLY RATE:

Delivery Voltage Level	Distribution below 69 kV		69 kV & above
	CILC-1(G)	CILC-1(D)	CILC-1(T)
Maximum Demand Level	200-499 kW	500 kW & above	
Customer Charge: $2,225.00	$~~125.00~~150.00		$~~225.00~~250.00
Demand Charges:			
Base Demand Charges:			
per kW of Maximum Demand	~~$3.90~~	$4.00	$4.20	None
per kW of Load Control On-Peak Demand	$~~2.60~~2.64		$~~2.90~~3.00
$~~3.00~~3.20			
per kW of Firm On-Peak Demand	$~~9.60~~10.00		$~~10.50~~10.90
$~~11.20~~11.70			
Capacity Payment and Conservation Charge:			
CILC-1(G)	See Sheet No. 8.030.1		
CILC-1(D)	See Sheet No. 8.030.1		
CILC-1(T)	See Sheet No. 8.030.1		
Non-Fuel Energy Charges:			
Base Energy Charges:			
On-Peak Period charge per kWh	~~1.480~~1.490 ¢		~~0.954~~1.004 ¢
~~0.900~~0.934 ¢			
Off-Peak Period charge per kWh	~~1.480~~1.490 ¢		~~0.954~~1.004 ¢
~~0.900~~0.934 ¢			
Environmental Charge	See Sheet No. 8.030.1		
Additional Charges:			
Fuel Charge	See Sheet No. 8.030.1		
Storm Charge	See Sheet No. 8.040		
Franchise Fee	See Sheet No. 8.031		
Tax Clause	See Sheet No. 8.031		

Minimum: The Customer Charge plus the Base Demand Charges.

(Continued on Sheet No. 8.652)

160001 Hearing Exhibits 00404

COMMERCIAL/INDUSTRIAL DEMAND REDUCTION RIDER (CDR)
(OPTIONAL)

AVAILABLE:

In all territory served. Available to any commercial or industrial customer receiving service under Rate Schedules GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, or HLFT through the execution of a Commercial/Industrial Demand Reduction Rider Agreement in which the load control provisions of this rider can feasibly be applied.

LIMITATION OF AVAILABILITY:

This Rider may be modified or withdrawn subject to determinations made under Commission Rules 25-17.0021(4), F.A.C., Goals for Electric Utilities and 25-6.0438, F.A.C., Non-Firm Electric Service - Terms and Conditions or any other Commission determination.

APPLICATION:

For electric service provided to any commercial or industrial customer receiving service under Rate Schedule GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, or HLFT who as a part of the Commercial/Industrial Demand Reduction Rider Agreement between the Customer and the Company, agrees to allow the Company to control at least 200 kW of the Customer's load, or agrees to operate Backup Generation Equipment (see Definitions) and designate (if applicable) additional controllable demand to serve at least 200 kW of the Customer's own load during periods when the Company is controlling load. A Customer shall enter into a Commercial/Industrial Reduction Demand Rider Agreement with the Company to be eligible for this Rider. To establish the initial qualification for this Rider, the Customer must have had a Utility Controlled Demand during the summer Controllable Rating Period (April 1 through October 31) for at least three out of seven months of at least 200 kW greater than the Firm Demand level specified in Section 4 of the Commercial/Industrial Demand Reduction Rider Agreement. The Utility Controlled Demand shall not be served on a firm service basis until service has been terminated under this Rider.

LIMITATION OF SERVICE:

Customers participating in the General Service Load Management Program (FPL "Business On Call" Program) are not eligible for this Rider.

MONTHLY RATE:

All rates and charges under Rate Schedules GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, HLFT shall apply. In addition, the applicable Monthly Administrative Adder and Utility Controlled Demand Credit shall apply.

MONTHLY ADMINISTRATIVE ADDER:

Rate Schedule	Adder
GSD-1	$~~100.00~~125.00
GSDT-1, HLFT (21-499 kW)	$~~100.00~~125.00
GSLD-1, GSLDT-1, HLFT (500-1,999 kW)	$~~150.00~~175.00
GSLD-2, GSLDT-2, HLFT (2,000 kW or greater)	$75.00
GSLD-3, GSLDT-3	$225.00

UTILITY CONTROLLED DEMAND CREDIT:

A monthly credit of ($8.20) per kW is allowed based on the Customer's Utility Controlled Demand.

UTILITY CONTROLLED DEMAND:

The Utility Controlled Demand for a month in which there are no load control events during the Controllable Rating Period shall be the sum of the Customer's kWh usage during the hours of the applicable Controllable Rating Period, divided by the total number of hours in the applicable Controllable Rating Period, less the Customer's Firm Demand.

In the event of Load Control occurring during the Controllable Rating Period, the Utility Controlled Demand shall be the sum of the Customer's kWh usage during the hours of the applicable Controllable Rating Period less the sum of the Customer's kWh usage during the Load Control Period, divided by the number of non-load control hours occurring during the applicable Controllable Rating Period, less the Customer's Firm Demand.

(Continued on Sheet No. 8.681)

(Continued from Sheet No. 8.715)

REMOVAL OF FACILITIES:

If Street Lighting facilities are removed either by Customer request or termination or breach of the agreement, the Customer shall pay FPL an amount equal to the original installed cost of the removed facilities less any salvage value and any depreciation (based on current depreciation rates as approved by the Florida Public Service Commission) plus removal cost.

MONTHLY RATE:

Luminaire Type		Lamp Size Initial Lumens/Watts		kWh/Mo. Estimate	Charge for FPL-Owned Unit ($) Fixtures	Maintenance	Energy Non-Fuel **	Total ***	Charge for Customer-Owned Unit $) **** Relamping/ Energy	Energy Only
High Pressure Sodium Vapor		6,300	70	29	$3.89	1.85	0.83	6.57	$2.69	$0.83
" "		9,500	100	41	$3.96	1.86	~~1.17~~1.18	~~6.99~~7.00	$~~3.04~~3.05	$~~1.17~~1.18
" "		16,000	150	60	$4.08	1.89	~~1.71~~1.73	~~7.68~~7.70	$~~3.61~~3.63	$~~1.71~~1.73
" "		22,000	200	88	$6.18	2.41	~~2.51~~2.53	~~11.10~~11.12	$~~4.90~~4.92	$~~2.51~~2.53
" "		50,000	400	168	$6.24	2.42	~~4.79~~4.84	~~13.45~~13.50	$~~7.19~~7.24	$~~4.79~~4.84
" "	*	27,500	250	116	$6.58	2.63	~~3.31~~3.34	~~12.52~~12.55	$~~5.91~~5.94	$~~3.31~~3.34
" "	*	140,000	1,000	411	$9.90	4.71	~~11.71~~	~~26.32~~	~~$16.46~~11.83	26.44 ~~$11.71~~11.83
Mercury Vapor	*	6,000	140	62	$3.07	1.66	~~1.77~~1.78	~~6.50~~6.51	$~~3.44~~3.45	$~~1.77~~1.78
" "	*	8,600	175	77	$3.12	1.66	~~2.19~~	~~6.97~~2.22	7.00	$~~3.86~~3.89 ~~$2.19~~2.22
" "	*	11,500	250	104	$5.21	2.40	~~2.96~~2.99	~~10.57~~10.60	$~~5.37~~5.40	$~~2.96~~2.99
" "	*	21,500	400	160	$5.18	2.36	~~4.56~~4.61	~~12.10~~12.15	$~~6.93~~6.98	$~~4.56~~4.61

* These units are closed to new FPL installations.
** The non-fuel energy charge is ~~2.850~~2.879 ¢ per kWh.
*** Bills rendered based on "Total" charge. Unbundling of charges is not permitted.
**** New customer-owned facilities are closed to this rate effective January 1, 2017.

Charges for other FPL-owned facilities:

Wood pole used only for the street lighting system	$4.92
Concrete pole used only for the street lighting system	$6.74
Fiberglass pole used only for the street lighting system	$7.98
Steel pole used only for the street lighting system *	$6.74
Underground conductors not under paving	3.810 ¢ per foot
Underground conductors under paving	9.310 ¢ per foot

The Underground conductors under paving charge will not apply where a CIAC is paid pursuant to section "a)" under "Customer Contributions." The Underground conductors not under paving charge will apply in these situations.

(Continued on Sheet No. 8.717)

160001 Hearing Exhibits 00406

(Continued from Sheet No. 8.716)

On Customer-owned Street Lighting Systems, where Customer contracts to relamp at no cost to FPL, the Monthly Rate for non-fuel energy shall be ~~2.850~~2.879 ¢ per kWh of estimated usage of each unit plus adjustments. On Street Lighting Systems, where the Customer elects to install Customer-owned monitoring systems, the Monthly Rate for non-fuel energy shall be ~~2.850~~2.879 ¢ per kWh of estimated usage of each monitoring unit plus adjustments. The minimum monthly kWh per monitoring device will be 1 kilowatt-hour per month, and the maximum monthly kWh per monitoring device will be 5 kilowatt-hours per month.

During the initial installation period:
Facilities in service for 15 days or less will not be billed;
Facilities in service for 16 days or more will be billed for a full month.

WILLFUL DAMAGE:

Upon the **second** occurrence of willful damage to any FPL-owned facilities, the Customer will be responsible for the cost incurred for repair or replacement. If the lighting fixture is damaged, based on prior written instructions from the Customer, FPL will:

a) Replace the fixture with a shielded cutoff cobrahead. The Customer shall pay $280.00 for the shield plus all associated costs. However, if the Customer chooses to have the shield installed after the first occurrence, the Customer shall only pay the $280.00 cost of the shield; or

b) Replace with a like unshielded fixture. For this, and each subsequent occurrence, the Customer shall pay the costs specified under "Removal of Facilities"; or

c) Terminate service to the fixture.

Option selection shall be made by the Customer in writing and apply to all fixtures which FPL has installed on the Customer's behalf. Selection changes may be made by the Customer at any time and will become effective ninety (90) days after written notice is received.

Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

SPECIAL CONDITIONS:

Customers whose lights are turned off during sea turtle nesting season will receive a credit equal to the fuel charges associated with the fixtures that are turned off.

TERM OF SERVICE:

Initial term of ten (10) years with automatic, successive five (5) year extensions unless terminated in writing by either FPL or the Customer at least ninety (90) days prior to the current term's expiration.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

160001 Hearing Exhibits 00407

STREET LIGHTING METERED SERVICE

RATE SCHEDULE: SL-1M

AVAILABLE:

In all territory served.

APPLICATION:

For customer-owned lighting of streets and roadways, whether public or private, which are thoroughfares for normal flow of vehicular traffic. Lighting for other applications such as: municipally and privately-owned parking lots; parks and recreational areas; or any other area not expressly defined above, is not permitted under this schedule.

SERVICE:

Single phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	~~$13.00~~14.00
Non-Fuel Energy Charges:	
Base Energy Charge	~~2.795~~2.827 ¢ per kWh
Conservation Charge	See Sheet No. 8.030
Capacity Payment Charge	See Sheet No. 8.030
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum:	~~$13.00~~14.00

TERM OF SERVICE:

Not less than one (1) year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

PREMIUM LIGHTING

RATE SCHEDULE: PL-1

AVAILABLE:

In all territory served.

APPLICATION:

FPL-owned lighting facilities not available under rate schedule SL-1 and OL-1. To any Customer for the sole purpose of lighting streets, roadways and common areas, other than individual residential locations. This includes but is not limited to parking lots, homeowners association common areas, or parks.

SERVICE:

Service will be unmetered and will include lighting installation, lamp replacement and facilities maintenance for FPL-owned lighting systems. It will also include energy from dusk each day until dawn the following day.

The Company, while exercising reasonable diligence at all times to furnish service hereunder, does not guarantee continuous lighting and will not be liable for damages for any interruption, deficiency or failure of service, and reserves the right to interrupt service at any time for necessary repairs to lines or equipment.

LIMITATION OF SERVICE:

Installation shall be made only when, in the judgement of the Company, the location and the type of the facilities are, and will continue to be, easily and economically accessible to the Company equipment and personnel for both construction and maintenance.

Stand-by, non-firm, or resale service is not permitted hereunder.

TERM OF SERVICE:

The term of service is (20) twenty years. At the end of the term of service, the Customer may elect to execute a new agreement based on the current estimated replacement costs. The Company will retain ownership of these facilities.

FACILITIES PAYMENT OPTION:

The Customer will pay for the facilities in a lump sum in advance of construction. The amount will be the Company's total work order cost for these facilities times the Present Value Revenue Requirement (PVRR) multiplier of ~~1.1942.~~1.1961. Monthly Maintenance and Energy charges will apply for the term of service.

FACILITIES SELECTION:

Facilities selection shall be made by the Customer in writing by executing the Company's Premium Lighting Agreement.

(Continued on Sheet No. 8.721)

160001 Hearing Exhibits 00409

(Continued from Sheet No. 8.720)

MONTHLY RATE :

Facilities:

Paid in full:	Monthly rate is zero, for Customer's who have executed a Premium Lighting Agreement before March 1, 2010:
10 years payment option:	~~1.358~~1.362% of total work order cost.
20 years payment option:	~~0.920~~0.925% of total work order cost.

Maintenance: FPL's estimated costs of maintaining lighting facilities.

Billing: FPL reserves the right to assess a charge for the recovery of any dedicated billing system developed solely for this rate.

Energy: KWH Consumption for fixtures shall be estimated using the following formula:

$$KWH = \frac{\text{Unit Wattage (usage)} \times 353.3 \text{ hours per month}}{1000}$$

Non-Fuel Energy	~~2.850~~2.879 ¢/kWh
Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

During the initial installation period:
Facilities in service for 15 days or less will not be billed;
Facilities in service for 16 days or more will be billed for a full month.

MINIMUM MONTHLY BILL:

The minimum monthly bill shall be the applicable Facilities Maintenance and Billing charges.

(Continued on Sheet No. 8.722)

160001 Hearing Exhibits 00410

(Continued from Sheet No. 8.721)

EARLY TERMINATION:

If the Customer no longer wishes to receive service under this schedule, the Customer may terminate the Premium Lighting Agreement by giving at least (90) ninety days advance written notice to the Company. Upon early termination of service, the Customer shall pay an amount computed by applying the following Termination Factors to the installed cost of the facilities, based on the year in which the Agreement was terminated. These Termination Factors will not apply to Customers who elected to pay for the facilities in a lump sum in lieu of a monthly payment.

FPL may also charge the Customer for the cost to the utility for removing the facilities.

Ten (10) Years Payment Option	Termination Factor	Twenty (20) Years Payment Option	Termination Factor
1	~~1.1942~~1.2100	1	~~1.1942~~1.2100
2	~~1.0312~~1.0410	2	~~1.0838~~1.0934
3	~~0.9475~~0.9588	3	~~1.0568~~1.0679
4	~~0.8575~~0.8698	4	~~1.0277~~1.0403
5	~~0.7605~~0.7733	5	~~0.9964~~1.0104
6	~~0.6560~~0.6688	6	~~0.9627~~0.9781
7	~~0.5435~~0.5556	7	~~0.9264~~0.9430
8	~~0.4224~~0.4329	8	~~0.8873~~0.9050
9	~~0.2919~~0.3000	9	~~0.8452~~0.8638
10	~~0.1513~~0.1560	10	~~0.7999~~0.8192
>10	0.0000	11	~~0.7510~~0.7709
		12	~~0.6984~~0.7185
		13	~~0.6418~~0.6618
		14	~~0.5808~~0.6004
		15	~~0.5151~~0.5338
		16	~~0.4443~~0.4616
		17	~~0.3681~~0.3835
		18	~~0.2861~~0.2988
		19	~~0.1977~~0.2071
		20	~~0.1025~~0.1077
		>20	0.0000

WILLFUL DAMAGE:

In the event of willful damage to these facilities, FPL will provide the initial repair of each installed item at its expense. Upon the second occurrence of willful damage, and subsequent occurrence to these FPL-owned facilities, the Customer will be responsible for the cost for repair or replacement.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

OUTDOOR LIGHTING

RATE SCHEDULE OL-1

AVAILABLE:

In all territory served.

APPLICATION:

For year-round outdoor security lighting of yards, walkways and other areas. Lights to be served hereunder shall be at locations which are easily and economically accessible to Company vehicles and personnel for construction and maintenance.

It is intended that Company-owned security lights will be installed on existing Company-owned electric facilities, or short extension thereto, in areas where a street lighting system is not provided or is not sufficient to cover the security lighting needs of a particular individual or location. Where more extensive security lighting is required, such as for large parking lots or other commercial areas, the Customer will provide the fixtures, supports and connecting wiring; the Company will connect to the Customer's system and provide the services indicated below.

SERVICE:

Service includes lamp renewals, energy from approximately dusk each day until approximately dawn the following day, and maintenance of Company-owned facilities. The Company will replace all burned-out lamps and will maintain its facilities during regular daytime working hours as soon as practicable following notification by the Customer that such work is necessary. The Company shall be permitted to enter the Customer's premises at all reasonable times for the purpose of inspecting, maintaining, installing and removing any or all of its equipment and facilities.

The Company, while exercising reasonable diligence at all times to furnish service hereunder, does not guarantee continuous lighting and will not be liable for damages for any interruption, deficiency or failure of service, and reserves the right to interrupt service at any time for necessary repairs to lines or equipment.

LIMITATION OF SERVICE:

This schedule is not available for service normally supplied on the Company's standard street lighting schedules. Company-owned facilities will be installed only on Company-owned poles. Customer-owned facilities will be installed only on Customer-owned poles. Overhead conductors will not be installed in any area designated as an underground distribution area, or any area, premises or location served from an underground source. Customer must have an active house or premise account associated with this service. Stand-by or resale service not permitted hereunder.

MONTHLY RATE:

Luminaire Type		Lamp Size Initial Lumens/Watts		KWH/Mo. Estimate	Charge for Company-Owned Unit ($) Fixtures	Maintenance	Energy Non-Fuel **	Total	Charge for Customer-Owned Unit ($) Relamping/ Energy	Energy Only
High Pressure Sodium Vapor		6,300	70	29	$5.05	$1.90	$~~0.84~~0.89	~~7.79~~7.84	$~~2.69~~2.74	$~~0.84~~0.89
" "		9,500	100	41	$5.16	$1.90	$~~1.19~~1.26		~~8.25~~8.32	$~~3.04~~3.11
$~~1.19~~1.26										
" "		16,000	150	60	$5.34	$1.93	$~~1.74~~1.84	~~9.01~~9.11	$~~3.62~~3.72	$~~1.74~~1.84
" "		22,000	200	88	$7.77	$2.49	$~~2.55~~2.70		~~12.81~~12.96	$~~4.98~~5.13
$~~2.55~~2.70										
" "		50,000	400	168	$8.27	$2.45	$~~4.88~~5.16		~~15.60~~15.88	$~~7.27~~7.55
$~~4.88~~5.16										
" "	*	12,000	150	60	$5.34	$1.93	$~~1.74~~1.84		~~9.01~~9.11	$~~3.89~~3.99
$~~1.74~~1.84										
Mercury Vapor	*	6,000	140	62	$3.88	$1.70	$~~1.80~~1.91		~~7.38~~7.49	$~~3.46~~3.57
$~~1.80~~1.91										
" "	*	8,600	175	77	$3.90	$1.70	$~~2.23~~2.37		~~7.83~~7.97	$~~3.89~~4.03
$~~2.23~~2.37										

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Effective: January 1, ~~2017~~2018

"	"	*	21,500	400	160	$6.39	$2.40	$~~4.64~~4.92	~~13.43~~13.71	$~~6.98~~7.26

$~~4.64~~4.92

* These units are closed to new Company installations.

** The non-fuel energy charge is ~~2.902~~3.073 ¢ per kWh.

(Continued on Sheet No. 8.726)

(Continued from Sheet No. 8.725)

Charges for other Company-owned facilities:

Wood pole and span of conductors:	$11.14
Concrete pole and span of conductors:	$~~15.03~~15.04
Fiberglass pole and span of conductors:	$17.68
Steel pole used only for the street lighting system *	$~~15.03~~15.04
Underground conductors (excluding trenching)	$0.085 per foot
Down-guy, Anchor and Protector	$10.13

For Customer-owned outdoor lights, where the Customer contracts to relamp at no cost to FPL, the monthly rate for non-fuel energy shall be $~~2.902~~3.073¢ per kWh of estimated usage of each unit plus adjustments.

Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Clause	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

TERM OF SERVICE:

Not less than one year. In the event the Company installs any facilities for which there is an added monthly charge, the Term of Service shall be for not less than three years.

If the Customer terminates service before the expiration of the initial term of the agreement, the Company may require reimbursement for the total expenditures made to provide such service, plus the cost of removal of the facilities installed less the salvage value thereof, and less credit for all monthly payments made for Company-owned facilities.

WILLFUL DAMAGE:

In the event of willful damage to these facilities, FPL will provide the initial repair of each installed item at its expense. Upon the second occurrence of willful damage, and subsequent occurrence to these FPL-owned facilities, the Customer will be responsible for the cost for repair or replacement.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

COMPANY-OWNED FACILITIES:

Company-owned luminaires normally will be mounted on Company's existing distribution poles and served from existing overhead wires. The Company will provide one span of secondary conductor from existing secondary facilities to a Company-owned light at the Company's expense. When requested by the Customer, and at the option of the Company, additional spans of wire or additional poles or underground conductors may be installed by the Company upon agreement by the Customer to use the facilities for a minimum of three years and pay each month the charges specified under MONTHLY RATE.

MONTHLY RATE

The Customer will make a lump sum payment for the cost of changes in the height of existing poles or the installation of additional poles in the Company's distribution lines or the cost of any other facilities required for the installation of lights to be served hereunder.

(Continued on Sheet No. 8.727)

160001 Hearing Exhibits 00414

RECREATIONAL LIGHTING

(Closed Schedule)

RATE SCHEDULE: RL-1

AVAILABLE:

In all territory served. Available to any customer, who, as of January 16, 2001, was either taking service pursuant to this schedule or had a fully executed Recreational Lighting Agreement with the Company.

APPLICATION:

For FPL-owned facilities for the purpose of lighting community recreational areas. This includes, but is not limitied to, baseball, softball, football, soccer, tennis, and basketball.

SERVICE:

Service will be metered and will include lighting installation, lamp replacement and facilities maintenance for FPL-owned lighting systems.

The Company, while exercising reasonable diligence at all times to furnish service hereunder, does not guarantee continuous lighting and will not be liable for damages for any interruption, deficiency or failure of service, and reserves the right to interrupt service at any time for necessary repairs to lines or equipment.

LIMITATION OF SERVICE:

Installation shall be made only when, in the judgement of the Company, the location and the type of the facilities are, and will continue to be, easily and economically accessible to the Company equipment and personnel for both construction and maintenance.

Stand-by, non-firm, or resale service is not permitted hereunder.

TERM OF SERVICE:

The term of service is (20) twenty years. At the end of the term of service, the Customer may elect to execute a new Agreement based on the current estimated replacement costs. The Company will retain ownership of these facilities.

FACILITIES PAYMENT OPTION:

The Customer will pay for the facilities in a lump sum in advance of construction. The amount will be the Company's total work order cost for these facilities times the Present Value Revenue Requirement (PVRR) multiplier of ~~1.1942.~~1.1961. Monthly Maintenance and energy charges will apply for the term of service.

FACILITIES SELECTION:

Facilities selection shall be made by the Customer in writing by executing the Company's Recreational Lighting Agreement.

(Continued on Sheet No. 8.744)

160001 Hearing Exhibits 00415

(Continued from Sheet No. 8.743)

MONTHLY RATE :

Facilities:

Paid in full:	Monthly rate is zero.
10 years payment option:	~~1.358~~1.364% of total work order cost.*
20 years payment option:	~~0.920~~0.926% of total work order cost.*

* Both (10) ten and (20) twenty year payment options are closed to new service, and are only available for the duration of the term of service of those customers that have fully executed a Recreational Lighting Agreement with the Company before January 16, 2001.

Maintenance:	FPL's estimated costs of maintaining lighting facilities.
Billing:	FPL reserves the right to assess a charge for the recovery of any dedicated billing system developed solely for this rate.
Charge Per Month:	Company's otherwise applicable general service rate schedule.
Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

MINIMUM MONTHLY BILL:

As provided in the otherwise applicable rate schedule, plus the Facilities Maintenance and Billing charges.

(Continued on Sheet No. 8.745)

160001 Hearing Exhibits 00416

(Continued from Sheet No. 8.744)

EARLY TERMINATION:

If the Customer no longer wishes to receive service under this schedule, the Customer may terminate the Recreational Lighting Agreement by giving at least (90) ninety days advance written notice to the Company. Upon early termination of service, the Customer shall pay an amount computed by applying the following Termination Factors to the installed cost of the facilities, based on the year in which the Agreement was terminated. These Termination Factors will not apply to Customers who elected to pay for the facilities in a lump sum in lieu of a monthly payment.

FPL may also charge the Customer for the cost to the utility for removing the facilities.

Ten (10) Years Payment Option	Termination Factor	Twenty (20) Years Payment Option	Termination Factor
1	~~1.1942~~1.2100	1	~~1.1942~~1.2100
2	~~1.0312~~1.0410	2	~~1.0838~~1.0934
3	~~0.9475~~0.9588	3	~~1.0568~~1.0679
4	~~0.8575~~0.8698	4	~~1.0277~~1.0403
5	~~0.7605~~0.7733	5	~~0.9964~~1.0104
6	~~0.6560~~0.6688	6	~~0.9627~~0.9781
7	~~0.5435~~0.5556	7	~~0.9264~~0.9430
8	~~0.4224~~0.4329	8	~~0.8873~~0.9050
9	~~0.2919~~0.3000	9	~~0.8452~~0.8638
10	~~0.1513~~0.1560	10	~~0.7999~~0.8192
>10	0.0000	11	~~0.7510~~0.7709
		12	~~0.6984~~0.7185
		13	~~0.6418~~0.6618
		14	~~0.5808~~0.6004
		15	~~0.5151~~0.5338
		16	~~0.4443~~0.4616
		17	~~0.3681~~0.3835
		18	~~0.2861~~0.2988
		19	~~0.1977~~0.2071
		20	~~0.1025~~0.1077
		>20	0.0000

WILLFUL DAMAGE:

In the event of willful damage to these facilities, FPL will provide the initial repair of each installed item at its expense. Upon the second occurrence of willful damage, and subsequent occurrence to these FPL-owned facilities, the Customer will be responsible for the cost for repair or replacement.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

STANDBY AND SUPPLEMENTAL SERVICE

RATE SCHEDULE: SST-1

AVAILABLE:

In all territory served by the Company. Service under this rate schedule is on a customer by customer basis subject to the completion of arrangements necessary for implementation.

APPLICATION:

For electric service to any Customer, at a point of delivery, whose electric service requirements for the Customer's load are supplied or supplemented from the Customer's generation equipment at that point of service and require standby and/or supplemental service. For purposes of determining applicability of this rate schedule, the following definitions shall be used:

(1) "Standby Service" means electric energy or capacity supplied by the Company to replace energy or capacity ordinarily generated by the Customer's own generation equipment during periods of either scheduled (maintenance) or unscheduled (backup) outages of all or a portion of the Customer's generation.

(2) "Supplemental Service" means electric energy or capacity supplied by the Company in addition to that which is normally provided by the Customer's own generation equipment.

A Customer is required to take service under this rate schedule if the Customer's total generation capacity is more than 20% of the Customer's total electrical load and the Customer's generators are not for emergency purposes only.

Customers taking service under this rate schedule shall enter into a Standby and Supplemental Service Agreement ("Agreement"); however, failure to execute such an agreement will not pre-empt the application of this rate schedule for service.

SERVICE:

Three phase, 60 hertz, and at the available standard voltage. All service supplied by the Company shall be furnished through one metering point. Resale of service is not permitted hereunder.

Transformation Rider - TR, Sheet No. 8.820, does not apply to Standby Service.

MONTHLY RATE:

STANDBY SERVICE

Delivery Voltage:	Below 69 kV			69kV & Above
Contract Standby Demand:	SST-1(D1) Below 500 kW	SST-1(D2) 500 to 1,999 kW	SST-1(D3) 2,000 kW & Above	SST-1(T) All Levels
Customer Charge:	$125.00	$125.00	$425.00	$1,800.00
Demand Charges:				
Base Demand Charges:				
Distribution Demand Charge per kW of Contract Standby Demand	$3.00	$3.00	$3.00	N/A
Reservation Demand Charge per kW	$1.48	$1.48	$1.48	$~~1.33~~1.35
Daily Demand Charge per kW for each daily maximum On-Peak Standby Demand	$0.70	$0.70	$0.70	$0.44
Capacity Payment and Conservation Charges	See Sheet No. 8.030.1			

(Continued on Sheet No. 8.751)

(Continued from Sheet No. 8.750)

Delivery Voltage:	Below 69 kV			69 kV & Above
	SST-1(D1)	SST-1(D2)	SST-1(D3)	SST-1(T)
Contract Standby Demand:	Below 500 kW	500 to 1,999 kW	2,000 kW & Above	All Levels
Non-Fuel Energy Charges:				
Base Energy Charges:				
On-Peak Period charge per kWh	~~0.707~~0.711 ¢	~~0.707~~0.711 ¢	~~0.707~~0.711 ¢	0.707 ¢
Off-Peak Period charge per kWh	~~0.707~~0.711 ¢	~~0.707~~0.711 ¢	~~0.707~~0.711 ¢	0.707 ¢

Environmental Charge — See Sheet No. 8.030.1

Additional Charges:

Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the Base Demand Charges.

DEMAND CALCULATION:

The Demand Charge for Standby Service shall be (1) the charge for Distribution Demand **plus** (2) the greater of the sum of the Daily Demand Charges **or** the Reservation Demand Charge times the maximum On-Peak Standby Demand actually registered during the month **plus** (3) the Reservation Demand Charge times the difference between the Contract Standby Demand and the maximum On-Peak Standby Demand actually registered during the month.

SUPPLEMENTAL SERVICE

Supplemental Service shall be the total power supplied by the Company minus the Standby Service supplied by the Company during the same metering period. The charge for all Supplemental Service shall be calculated by applying the applicable retail rate schedule, excluding the customer charge.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

CONTRACT STANDBY DEMAND:

The level of Customer's generation requiring Standby Service as specified in the Agreement. This Contract Standby Demand will not be less than the maximum load actually served by the Customer's generation during the current month or prior 23-month period less the amount specified as the Customer's load which would not have to be served by the Company in the event of an outage of the Customer's generation equipment. For a Customer receiving only Standby Service as identified under Special Provisions, the Contract Standby Demand shall be maximum load actually served by the Company during the current month or prior 23-month period.

A Customer's Contract Standby Demand may be re-established to allow for the following adjustments:

1. Demand reduction resulting from the installation of FPL Demand Side Management Measures or FPL Research Project efficiency measures; or

(Continued on Sheet No. 8.752)

160001 Hearing Exhibits 00419

INTERRUPTIBLE STANDBY AND SUPPLEMENTAL SERVICE
(OPTIONAL)

RATE SCHEDULE: ISST-1

AVAILABLE:

In all territory served by the Company. Service under this rate schedule is on a customer by customer basis subject to the completion of arrangements necessary for implementation.

LIMITATION OF AVAILABILITY:

This schedule may be modified or withdrawn subject to determinations made under Commission Rule 25-6.0438, F.A.C., Non-Firm Electric Service - Terms and Conditions or any other Commission determination.

APPLICATION:

A Customer who is eligible to receive service under the Standby and Supplemental Service (SST-1) rate schedule may, as an option, take service under this rate schedule, unless the Customer has entered into a contract to sell firm capacity and/or energy to the Company, and the Customer cannot restart its generation equipment without power supplied by the Company, in which case the Customer may only receive Standby and Supplemental Service under the Company's SST-1 rate schedule.

Customers taking service under this rate schedule shall enter into an Interruptible Standby and Supplemental Service Agreement ("Agreement"). This interruptible load shall not be served on a firm service basis until service has been terminated under this rate schedule.

SERVICE:

Three phase, 60 hertz, and at the available standard voltage.

A designated portion of the Customer's load served under this schedule is subject to interruption by the Company. Transformation Rider-TR, where applicable, shall only apply to the Customer's Contract Standby Demand for delivery voltage below 69 kV. Resale of service is not permitted hereunder.

MONTHLY RATE:

STANDBY SERVICE Delivery Voltage:		Distribution Below 69 kV ISST-1(D)	Transmission 69 kV & Above ISST-1(T)
Customer Charge:		$425.00	$1,800.00
Demand Charges:			
Base Demand Charges:			
Distribution Demand Charge per kW of Contract Standby Demand		$3.00	N/A
Reservation Demand Charge per kW of Interruptible Standby Demand		$~~0.25~~0.26	$0.30
Reservation Demand Charge per kW of Firm Standby Demand		$1.48	$~~1.33~~1.35
Daily Demand Charge per kW for each daily maximum On-Peak Interruptible Standby Demand		$0.70	$0.44
Daily Demand Charge per kW for each daily maximum On-Peak Firm Standby Demand		$~~0.12~~0.13	$0.12
Capacity Payment and Conservation Charges	See Sheet No. 8.030.1		
Non-Fuel Energy Charges:			
Base Energy Charges:			
On-Peak Period charge per kWh		~~0.707~~0.711 ¢	0.707 ¢
Off-Peak Period charge per kWh		~~0.707~~0.711 ¢	0.707 ¢
Environmental Charge	See Sheet No. 8.030.1		

(Continued on Sheet No. 8.761)

160001 Hearing Exhibits 00420

SEASONAL DEMAND – TIME OF USE RIDER – SDTR
(OPTIONAL)

RIDER: SDTR

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW. This is an optional rate available to customers otherwise served under the GSD-1 GSDT-1, GSLD-1, GSLDT-1, GSLD-2 or GSLDT-2 Rate Schedules.

SERVICE:
Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:
OPTION A: Non-Seasonal Standard Rate

Annual Maximum Demand	SDTR-1 21-499 kW	SDTR-2 500-1,999 kW	SDTR-3 2,000 kW or greater
Customer Charge:	$25.00	$75.00	$225.00
Demand Charges:			
Seasonal On-peak Demand Charge Per kW of Seasonal On-peak Demand	$~~10.10~~10.40	$~~11.40~~11.90	$~~12.00~~12.46
Non-Seasonal Demand Charge Per kW of Non- Seasonal Maximum Demand	$~~8.90~~9.00	$~~10.80~~11.30	$~~11.18~~11.78
Capacity Payment Charge:	See Sheet No. 8.030		
Conservation Charge:	See Sheet No. 8.030		
Energy Charges:			
Base Seasonal On-Peak Per kWh of Seasonal On-Peak Energy	~~8.093~~8.334 ¢	~~5.648~~5.896 ¢	~~4.538~~4.681 ¢
Base Seasonal Off-Peak Per kWh of Seasonal Off-Peak Energy	~~1.459~~1.503 ¢	~~1.143~~1.196 ¢	~~1.112~~1.169 ¢
Base Non-Seasonal Energy Charge Per kWh of Non-Seasonal Energy	~~2.035~~2.096 ¢ ~~1.427~~1.493 ¢	~~1.585~~1.657 ¢	
Environmental Charge:	See Sheet No. 8.030		
Additional Charges:			
Fuel Charge:	See Sheet No. 8.030		
Storm Charge:	See Sheet No. 8.040		
Franchise Fee:	See Sheet No. 8.031		
Tax Clause:	See Sheet No. 8.031		

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(Continued from Sheet No. 8.830)

OPTION B: Non-Seasonal Time of Use Rate

Annual Maximum Demand	SDTR-1 21-499 kW	SDTR-2 500-1,999 kW	SDTR-3 2,000 kW or greater
Customer Charge:	$25.00	$75.00	$225.00
Demand Charges:			
Seasonal On-peak Demand Charge $~~12.00~~12.46 Per kW of Seasonal On-peak Demand	$~~10.10~~10.40	$~~11.40~~11.90	
Non-Seasonal Demand Charge Per kW of Non- Seasonal Peak Demand	$~~8.90~~9.00	$~~10.80~~11.30	$~~11.18~~11.78
Capacity Payment Charge	See Sheet No. 8.030		
Conservation Charge	See Sheet No. 8.030		
Energy Charges:			
Base Seasonal On-Peak ~~4.538~~4.681 ¢ Per kWh of Seasonal On-Peak Energy	~~8.093~~8.334 ¢	~~5.648~~5.896 ¢	
Base Seasonal Off-Peak ~~1.112~~1.169 ¢ Per kWh of Seasonal Off-Peak Energy	~~1.459~~1.503 ¢	~~1.143~~1.196 ¢	
Base Non-Seasonal On-Peak ~~3.113~~3.223 ¢ Per kWh of Non-Seasonal On-Peak Energy	~~4.622~~4.762 ¢	~~3.384~~3.529 ¢	
Base Non-Seasonal Off-Peak ~~1.112~~1.169 ¢ Per kWh of Non-Seasonal Off-Peak Energy	~~1.459~~1.503 ¢	~~1.143~~1.196 ¢	
Environmental Charge	See Sheet No. 8.030		
Additional Charges:			
Fuel Charge	See Sheet No. 8.030		
Storm Charge	See Sheet No. 8.040		
Franchise Fee	See Sheet No. 8.031		
Tax Clause	See Sheet No. 8.031		

Minimum Charge: The Customer Charge plus the currently effective Demand Charges.

NON-SEASONAL RATING PERIODS (OPTION B only):

Non-Seasonal On-Peak Period:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through May 31 and October 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day.

Non-Seasonal Off-Peak Period:

All other hours.

(Continued On Sheet No. 8.832)

Appendix A

Distribution Substation Facilities
Monthly Rental and Termination Factors

The Monthly Rental Factor to be applied to the in-place value of the Distribution Substation Facilities as identified in the Long-Term Rental Agreement is as follows:

	Monthly Rental Factor
Distribution Substation Facilities	1.33%

Termination Fee for Initial 20 Year Period

If the Long-Term Rental Agreement for Distribution Substation Facilities is terminated by Customer during the Initial Term, Customer shall pay to Company a Termination Fee, such fee shall be computed by applying the following Termination Factors to the in-place value of the Facilities based on the year in which the Agreement is terminated:

Year Agreement Is Terminated	Termination Factors %	Year Agreement Is Terminated	Termination Factors %	Year Agreement Is Terminated	Termination Factors %
1	~~3.33~~3.36	8	~~11.11~~11.16	15	~~6.00~~6.01
2	~~5.98~~6.03	9	~~10.83~~10.88	16	~~4.87~~4.88
3	~~7.97~~8.03	10	~~10.36~~10.40	17	3.70
4	~~9.40~~9.47	11	~~9.73~~9.76	18	~~2.49~~2.48
5	~~10.36~~10.42	12	~~8.95~~8.98	19	1.25
6	~~10.92~~10.98	13	~~8.06~~8.08	20	0.00
7	~~11.15~~11.21	14	~~7.07~~7.08		

Termination Fee for Subsequent Extension Periods

If the Long-Term Rental Agreement for Distribution Substation Facilities is terminated by Customer during an Extension, Customer shall pay to Company a Termination Fee, such fee shall be computed based on the net present value of the remaining payments under the extension period by applying the Termination Factor based on the month terminated to the monthly rental payment amount.

Month Terminated	Termination Factor	Month Terminated	Termination Factor	Month Terminated	Termination Factor	Month Terminated	Termination Factor
1	~~49.992~~49.902	16	~~39.231~~39.177	31	~~27.386~~27.361	46	~~14.349~~14.343
2	~~49.307~~49.219	17	~~38.476~~38.424	32	~~26.555~~26.531	47	~~13.435~~13.429
3	~~48.616~~48.531	18	~~37.716~~37.667	33	~~25.719~~25.697	48	~~12.514~~12.510
4	~~47.922~~47.839	19	~~36.952~~36.904	34	~~24.878~~24.857	49	~~11.588~~11.584
5	~~47.223~~47.143	20	~~36.182~~36.137	35	~~24.031~~24.012	50	~~10.656~~10.653
6	~~46.519~~46.442	21	~~35.408~~35.365	36	~~23.178~~23.161	51	~~9.718~~9.715
7	~~45.811~~45.736	22	~~34.629~~34.587	37	~~22.321~~22.304	52	~~8.774~~8.772
8	~~45.099~~45.026	23	~~33.844~~33.805	38	~~21.457~~21.442	53	~~7.824~~7.822
9	~~44.381~~44.311	24	~~33.055~~33.017	39	~~20.589~~20.575	54	~~6.868~~6.866
10	~~43.660~~43.592	25	~~32.261~~32.225	40	~~19.714~~19.702	55	~~5.905~~5.904
11	~~42.933~~42.868	26	~~31.461~~31.427	41	~~18.834~~18.823	56	~~4.937~~4.936
12	~~42.202~~42.139	27	~~30.656~~30.624	42	~~17.949~~17.938	57	3.962
13	~~41.466~~41.406	28	~~29.847~~29.816	43	~~17.057~~17.048	58	2.981
14	~~40.726~~40.668	29	~~29.032~~29.003	44	~~16.160~~16.152	59	1.994
15	~~39.981~~39.925	30	~~28.211~~28.185	45	~~15.258~~15.250	60	1.000

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SERVICE CHARGES

A $25.00 service charge will be made for an initial connection.

A $13.00 Reconnection Charge will be made for the reconnection of service after disconnection for nonpayment or violation of a rule or regulation.

A $12.00 service charge will be made for the connection of an existing account.

A Returned Payment Charge as allowed by Florida Statute 68.065 shall apply for each check or draft dishonored by the bank upon which it is drawn. Termination of service shall not be made for failure to pay the Returned Payment Charge.

Charges for services due and rendered which are unpaid as of the past due date are subject to a Late Payment Charge of the greater of $5.00 or 1.5% applied to any past due unpaid balance of all accounts, except the accounts of federal, state, and local governmental entities, agencies, and instrumentalities. A Late Payment Charge shall be applied to the accounts of federal, state, and local governmental entities, agencies, and instrumentalities at a rate no greater than allowed, and in a manner permitted, by applicable law.

A $48.00 Field Collection Charge will be added to a customer's bill for electric service when a field visit is made and payment is collected on a delinquent account. If service is disconnected, or a current receipt of payment is shown at the time of the field visit, this charge will not be applied.

FPL may waive the Reconnection Charge, Returned Payment Charge, Late Payment Charge and Field Collection Charge for Customers affected by natural disasters or during periods of declared emergencies or once in any twelve (12) month period for any Customer who would otherwise have had a satisfactory payment record (as defined in 25-6.097(2) F.A.C.), upon acceptance by FPL of a reasonable explanation justifying a waiver. In addition, FPL may waive the charge for connection of an existing account and the charge for an initial connection for new or existing Customers affected by natural disasters or during periods of declared emergencies.

CONSERVATION INSPECTIONS AND SERVICES

Residential Dwelling Units:
A charge of $15.00 will be made for a computerized energy analysis in which a comprehensive on-site evaluation of the residence is performed.

Commercial/Industrial:
There is no charge for conservation inspections and services (Business Energy Services).

TEMPORARY/CONSTRUCTION SERVICE

APPLICATION:

For temporary electric service to installations such as fairs, exhibitions, construction projects, displays and similar installations.

SERVICE:

Single phase or three phase, 60 hertz at the available standard secondary distribution voltage. This service is available only when the Company has existing capacity in lines, transformers and other equipment at the requested point of delivery. The Customer's service entrance electrical cable shall not exceed 200 Amp capacity.

CHARGE:

The non-refundable charge must be paid in advance of installation of such facilities which shall include service and metering equipment.

Installing and removing overhead service and meter	$376.00
Connecting and disconnecting Customer's service cable to Company's direct-buried underground facilities including installation and removal of meter	$215.00

MONTHLY RATE:

This temporary service shall be billed under the appropriate rate schedule applicable to commercial and industrial type installations.

SPECIAL CONDITIONS:

If specific electrical service other than that stated above is required, the Company, at the Customer's request, will provide such service based on the estimated cost of labor for installing and removing such additional electrical equipment. This estimated cost will be payable in advance to the Company and subject to adjustment after removal of the required facilities. All Temporary/Construction services shall be subject to all of the applicable Rules, Regulations and Tariff charges of the Company, including Service Charges.

GENERAL SERVICE - NON DEMAND

RATE SCHEDULE: GS-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose with a demand of 20 kW or less.

SERVICE:

Single phase, 60 hertz and at any available standard distribution voltage. Three phase service will be provided without additional charge unless the Company's line extension policy is applicable thereto. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$10.00
Non-Fuel Energy Charges:	
Base Energy Charge	5.664 ¢ per kWh
Conservation Charge	See Sheet No. 8.030
Capacity Payment Charge	See Sheet No. 8.030
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
General Service Load Management Program (if applicable)	See Sheet No. 8.109
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum:	$10.00
Non-Metered Accounts:	A Customer Charge of $5.00 will apply to those accounts which are billed on an estimated basis and, at the Company's option, do not have an installed meter for measuring electric service. The minimum charge shall be $5.00.

SPECIAL PROVISIONS:

Energy used by commonly owned facilities of condominium, cooperative and homeowners' associations may qualify for the residential rate schedule as set forth on Sheet No. 8.211, Rider CU.

TERM OF SERVICE:

Not less than one (1) billing period.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE - NON DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: GST-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose with a demand of 20 kW or less. This is an optional rate available to General Service - Non Demand customers upon request subject to availability of meters.

SERVICE:

Single phase, 60 hertz and at any available standard distribution voltage. Three phase service will be provided without additional charge unless the Company's line extension policy is applicable thereto. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$10.00	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	10.459 ¢ per kWh	3.581 ¢ per kWh
Conservation Charge	See Sheet No. 8.030	
Capacity Payment Charge	See Sheet No. 8.030	
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
General Service Load Management Program (if applicable)	See Sheet No. 8.109	
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	
Minimum:	$10.00	

Initial service under this rate schedule shall begin on the first scheduled meter reading date following the installation of the time of use meter.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to l0 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.104)

GENERAL SERVICE DEMAND

RATE SCHEDULE: GSD-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW and less than 500 kW. Customers with a Demand of 20 kW or less may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 21 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$25.00
Demand Charges:	
Base Demand Charge	$9.40 per kW
Capacity Payment Charge	See Sheet No. 8.030, per kW
Conservation Charge	See Sheet No. 8.030, per kW
Non-Fuel Energy Charges:	
Base Energy Charge	2.096 ¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of 20 kW or less who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 21 kW times the Base Demand Charge; therefore the minimum charge is $222.40.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's thermal type meter or, at the Company's option, integrating type meter for the 30-minute period of Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: GSDT-1

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW and less than 500 kW. Customers with Demands of less than 21 kW may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 21 kW. This is an optional rate available to General Service Demand customers upon request subject to availability of meters.

SERVICE:
Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$25.00	
Demand Charges:		
Base Demand Charge	$9.40 per kW of Demand occurring during the On-Peak period.	
Capacity Payment Charge	See Sheet No. 8.030, per kW of Demand occurring during the On-Peak period.	
Conservation Charge	See Sheet No. 8.030, per kW of Demand occurring during the On-Peak period.	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	4.275 ¢ per kWh	1.131 ¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 21 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 21 kW times the Base Demand Charge, therefore the minimum charge is $222.40.

RATING PERIODS:
On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.108)

160001 Hearing Exhibits 00429

GENERAL SERVICE CONSTANT USAGE

RATE SCHEDULE: GSCU-1

AVAILABLE:

In all territory served.

APPLICATION:

Available to General Service - Non Demand customers that maintain a relatively constant kWh usage, and a demand of 20 kW or less. Eligibility is restricted to General Service customers whose Maximum kWh Per Service Day, over the current and prior 23 months, is within 5% of their average monthly kWh per service days calculated over the same 24-month period. Customers under this Rate Schedule shall enter into a General Service Constant Use Agreement. This is an optional Rate Schedule available to General Service customers upon request.

SERVICE:

Single phase, 60 hertz and at any available standard distribution voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$14.00
Non-Fuel Energy Charges:	
Base Energy Charge*	3.515 ¢ per Constant Usage kWh
Conservation Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Capacity Payment Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Environmental Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Additional Charges:	
Fuel Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Storm Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

* The fuel, storm and non-fuel energy charges will be assessed on the Constant Usage kWh

TERM OF SERVICE:

Initial term of service under this rate schedule shall be not less than one (1) billing period, unless there is a termination of service due to a Customer's violation of the General Service Constant Usage Agreement. Upon the Customer's violation of any of the terms of the General Service Constant Usage Agreement, service under this Rate Schedule will be terminated immediately. To terminate service, either party must provide thirty (30) days written notice to the other party prior to the desired termination date. Absent such notice, the term of service shall automatically be extended another billing period. In addition, if service under this Rate Schedule is terminated by either the Customer or the Company, the account may not resume service under this Rate Schedule for a period of at least one (1) year.

DEFINITIONS:

kWh Per Service Day – the total kWh in billing month divided by the number of days in the billing month

Maximum kWh Per Service Day - the highest kWh Per Service Day experienced over the current and prior 23 month billing periods

Constant Usage kWh – the Maximum kWh Per Service Day multiplied by the number of service days in the current billing period

(Continued on Sheet 8.123)

160001 Hearing Exhibits 00430

RESIDENTIAL SERVICE

RATE SCHEDULE: RS-1

AVAILABLE:

In all territory served.

APPLICATION:

For service for all domestic purposes in individually metered dwelling units and in duplexes and triplexes, including the separately-metered non-commercial facilities of a residential Customer (i.e., garages, water pumps, etc.). Also for service to commonly-owned facilities of condominium, cooperative and homeowners' associations as set forth on Sheet No. 8.211, Rider CU.

SERVICE:

Single phase, 60 hertz at available standard distribution voltage. Three phase service may be furnished but only under special arrangements. All residential service required on the premises by Customer shall be supplied through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$7.87
Non-Fuel Charges:	
Base Energy Charge:	
First 1,000 kWh	5.801 ¢ per kWh
All additional kWh	6.801 ¢ per kWh
Conservation Charge	See Sheet No. 8.030
Capacity Payment Charge	See Sheet No. 8.030
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Residential Load Control Program (if applicable)	See Sheet No. 8.217
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum:	$7.87

TERM OF SERVICE:

Not less than one (1) billing period.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

RESIDENTIAL TIME OF USE RIDER – RTR-1
(OPTIONAL)

RIDER: RTR-1

AVAILABLE:
In all territory served.

APPLICATION:

For service for all domestic purposes in individually metered dwelling units and in duplexes and triplexes, including the separately-metered non-commercial facilities of a residential Customer (i.e., garages, water pumps, etc.). Also for service to commonly-owned facilities of condominium, cooperative and homeowners' associations as set forth on Sheet No. 8.211, Rider CU. This is an optional rider available to residential customers served under the RS-1 Rate Schedule subject to availability of meters. Customers taking service under RTR-1 are not eligible for service under Rate Schedule RLP.

SERVICE:

Single phase, 60 hertz at available standard distribution voltage. Three phase may be supplied but only under special arrangements. All residential service required on the premises by Customer shall be supplied through one meter. Resale of service is not permitted hereunder.

Initial service under this rate schedule shall begin on the first scheduled meter reading date following the installation of the time of use meter. The Customer's first bill will reflect the lesser of the charges under Rate Schedule RS-1 or RTR-1.

MONTHLY RATE:

Except for the Customer Charge, all rates and charges under Rate Schedule RS-1 shall apply. In addition, the RTR-1 Customer Charge, the RTR-1 Base Energy and Fuel Charges and Credits applicable to on and off peak usage shall apply.

Customer Charge:	$7.87	
Base Energy Charges/Credits:	On-Peak Period	Off-Peak Period
Base Energy Charge	10.349 ¢ per kWh	(4.604) ¢ per kWh
Additional Charges/Credits:		
RTR Fuel Charge/Credit	See Sheet No. 8.030	
Minimum:	$7.87	

RATING PERIODS:

On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.204)

160001 Hearing Exhibits 00432

GENERAL SERVICE LARGE DEMAND

RATE SCHEDULE: GSLD-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer with a measured demand of 500 kW and less than 2,000 kW. Customers with demands of less than 500 kW may enter an agreement for service under this Rate Schedule based on a Demand Charge for a minimum of 500 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$75.00
Demand Charges:	
Base Demand Charge	$11.50 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	1.657 ¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charges	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is $5,825.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's thermal type meter or, at the Company's option, integrating type meter for the 30-minute period of Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE LARGE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE GSLDT-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer with a measured demand of 500 kW and less than 2,000 kW. Customers with demands of less than 500 kW may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 500 kW. This is an optional rate available to General Service Large Demand customers upon request subject to availability of meters.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$75.00	
Demand Charges:		
Base Demand Charge	$11.50 per kW of Demand occurring during the On-Peak period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	2.712 ¢ per kWh	1.196 ¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is $5,825.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.321)

160001 Hearing Exhibits 00434

CURTAILABLE SERVICE
(OPTIONAL)

RATE SCHEDULE: CS-1

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-1 (500 kW - 1,999 kW) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. Customers with demands of at least 200 kW but less than 500 kW may enter an agreement for service under this Rate Schedule based on a Demand Charge for a minimum of 500 kW.

SERVICE:
Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$100.00
Demand Charges:	
Base Demand Charge	$11.50 per kW of Demand.
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	1.657 ¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is $5,850.

CURTAILMENT CREDITS:
A monthly credit of ($1.93) per kW is allowed based on the current Non-Firm Demand. The Customer has the option to revise the Firm Demand once during the initial twelve (12) month period. Thereafter, subject to the Term of Service and/or the Provisions for Early Termination, a change to the Firm Demand may be made provided that the revision does not decrease the total amount of Non-Firm Demand during the lesser of: (i) the average of the previous 12 months; or (ii) the average of the number of billing months under this Rate Schedule.

CHARGES FOR NON-COMPLIANCE OF CURTAILMENT DEMAND:
If the Customer records a higher Demand during the current Curtailment Period than the Firm Demand, the Customer will be:

1. Rebilled at $1.93/kW for the prior 36 months or the number of months since the prior Curtailment Period, whichever is less, and
2. Billed a penalty charge of $4.16 kW for the current month.

The kW used for both the rebilling and penalty charge calculations is determined by taking the difference between the maximum Demand during the current Curtailment Period and the Firm Demand for a Curtailment Period.

(Continued on Sheet No. 8.331)

160001 Hearing Exhibits 00435

CURTAILABLE SERVICE - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: CST-1

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-1 (500 kW - 1,999 kW) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. This is an optional Rate Schedule available to Curtailable General Service Customers upon request. Customers with demands of at least 200 kW but less than 500 kW may enter an agreement for service under this Rate Schedule based on a Demand Charge for a minimum of 500 kW

SERVICE:

Single or three phase, 60 hertz and at any available distribution standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$100.00	
Demand Charges:		
Base Demand Charge	$11.50 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	2.712 ¢ per kWh	1.196 ¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is $5,850.

RATING PERIODS:

On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.341)

GENERAL SERVICE LARGE DEMAND

RATE SCHEDULE: GSLD-2

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer with a measured demand of 2,000 kW or more. Customers with demands of less than 2,000 kW may enter an agreement for service under this schedule based on a demand charge for a minimum of 2,000 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$225.00
Demand Charges:	
Base Demand Charge	$12.00 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	1.493 ¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a demand of less than 2,000 kW who enter an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is $24,225.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's metering equipment, for the 30-minute period of the Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE LARGE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: GSLDT-2

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer who has established a measured demand of 2,000 kW or more. Customers with demands of less than 2,000 kW may enter an agreement for service under this schedule based on a demand charge for a minimum of 2,000 kW.

SERVICE:

Three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$225.00	
Demand Charges:		
Base Demand Charge	$12.00 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	2.316 ¢ per kWh	1.169 ¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a demand of less than 2,000 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is $24,225.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.421)

160001 Hearing Exhibits 00438

HIGH LOAD FACTOR – TIME OF USE
(OPTIONAL)

RATE SCHEDULE: HLFT

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW. This is an optional rate schedule available to customers otherwise served under the GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, or GSLDT-2 Rate Schedules.

SERVICE:
Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Annual Maximum Demand	HLFT-1 21-499 kW	HLFT-2 500-1,999 kW	HLFT-3 2,000 kW or greater
Customer Charge:	$25.00	$75.00	$225.00
Demand Charges:			
On-peak Demand Charge	$11.10	$12.10	$12.20
Maximum Demand Charge	$2.30	$2.60	$2.60
Capacity Payment Charge	See Sheet No. 8.030, per kW of On-Peak Demand		
Conservation Charge	See Sheet No. 8.030, per kW of On-Peak Demand		
Non-Fuel Energy Charges:			
On-Peak Period per kWh	1.813 ¢	1.071 ¢	0.951 ¢
Off-Peak Period per kWh	1.131 ¢	1.023 ¢	0.944 ¢
Environmental Charge	See Sheet No. 8.030		
Additional Charges			
Fuel Charge	See Sheet No. 8.030		
Storm Charge	See Sheet No. 8.040		
Franchise Fee	See Sheet No. 8.031		
Tax Clause	See Sheet No. 8.031		

Minimum Charge: The Customer Charge plus the currently effective Demand Charges.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.426)

CURTAILABLE SERVICE
(OPTIONAL)

RATE SCHEDULE: CS-2

AVAILABLE:

In all territory served.

APPLICATION:

For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-2 (2,000 kW and above) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. Customers with demands of less than 2,000 kW may enter an Agreement for service under this schedule based on a Demand Charge for a minimum of 2,000 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$250.00
Demand Charges:	
Base Demand Charge	$12.00 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	1.493 ¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 2,000 kW who enter an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is $24,250.

CURTAILMENT CREDITS:

A monthly credit of ($1.93) per kW is allowed based on the current Non-Firm Demand. The Customer has the option to revise the Firm Demand once during the initial twelve (12) month period. Thereafter, subject to the Term of Service and/or the Provisions for Early Termination, a change to the Firm Demand may be made provided that the revision does not decrease the total amount of Non-Firm Demand during the lesser of: (i) the average of the previous 12 months; or (ii) the average of the number of billing months under this Rate Schedule.

CHARGES FOR NON-COMPLIANCE OF CURTAILMENT DEMAND:

If the Customer records a higher Demand during the current period than the Firm Demand, then the Customer will be:

1. Rebilled at $1.93 /kW for the prior 36 months or the number of months since the prior Curtailment Period, whichever is less, and
2. Billed a penalty charge of $4.16 /kW for the current month.

The kW used for both the rebilling and penalty charge calculations is determined by taking the difference between the maximum Demand during the current Curtailment Period and the contracted Firm Demand for a Curtailment Period.

(Continued on Sheet No. 8.433)

CURTAILABLE SERVICE - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: CST-2

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLDT-2 (2,000 kW and above) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. Customers with demands of less than 2,000 kW may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 2,000 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$250.00	
Demand Charges:		
Base Demand Charge	$12.00 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	2.316 ¢ per kWh	1.169 ¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 2,000 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is $24,250.

RATING PERIODS:

On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.441)

CURTAILABLE SERVICE - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: CST-3

AVAILABLE:

In all territory served.

APPLICATION:

For any commercial or industrial Customer who qualifies for Rate Schedule GSLDT-3 and will curtail this Demand by 200 kW or more upon request of the Company from time to time.

SERVICE:

Three phase, 60 hertz at the available transmission voltage of 69 kV or higher. The Customer will provide and maintain all transformers and related facilities necessary for handling and utilizing the power and energy delivered hereunder. All service required by the Customer at each separate point of delivery served hereunder shall be furnished through one meter at, or compensated to, the available transmission voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$2,025.00	
Demand Charges:		
Base Demand Charge	$9.30 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030.1	
Conservation Charge	See Sheet No. 8.030.1	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	1.227 ¢ per kWh	1.019 ¢ per kWh
Environmental Charge	See Sheet No. 8.030.1	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030.1	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.543)

CURTAILABLE SERVICE
(OPTIONAL)

RATE SCHEDULE: CS-3

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-3 and will curtail this Demand by 200 kW or more upon request of the Company from time to time.

SERVICE:
Three phase, 60 hertz at the available transmission voltage of 69 kV or higher. The Customer will provide and maintain all transformers and related facilities necessary for handling and utilizing the power and energy delivered hereunder. All service required by the Customer at each separate point of delivery served hereunder shall be furnished through one meter at, or compensated to, the available transmission voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$2,025.00
Demand Charges:	
Base Demand Charge	$9.30 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030.1
Conservation Charge	See Sheet No. 8.030.1
Non-Fuel Energy Charges:	
Base Energy Charge	1.074 ¢ per kWh
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum Charge: The Customer Charge plus the charge for the currently effective Base Demand.

CURTAILMENT CREDITS:
A monthly credit of ($1.93) per kW is allowed based on the current Non-Firm Demand. The Customer has the option to revise the Firm Demand once during the initial twelve (12) month period. Thereafter, subject to the Term of Service and/or the Provisions for Early Termination, a change to the Firm Demand may be made provided that the revision does not decrease the total amount of Non-Firm Demand during the lesser of: (i) the average of the previous 12 months; or (ii) the average of the number of billing months under this Rate Schedule.

CHARGES FOR NON-COMPLIANCE OF CURTAILMENT DEMAND:

If the Customer records a higher Demand during the current Curtailment Period than the Firm Demand, then the Customer will be:

1. Rebilled at $1.93 /kW for the prior 36 months or the number of months since the prior Curtailment Period, whichever is less, and
2. Billed a penalty charge of $4.16 /kW for the current month.

The kW used for both the rebilling and penalty charge calculations is determined by taking the difference between the maximum Demand during the current Curtailment Period and the Firm Demand for a Curtailment Period.

(Continued on Sheet No. 8.546)

160001 Hearing Exhibits 00443

GENERAL SERVICE LARGE DEMAND

RATE SCHEDULE: GSLD-3

AVAILABLE:

In all territory served.

APPLICATION:

For service required for commercial or industrial lighting, power and any other purpose to any Customer who has service supplied at a transmission voltage of 69 kV or higher.

SERVICE:

Three phase, 60 hertz at the available transmission voltage of 69 kV or higher. The Customer will provide and maintain all transformers and related facilities necessary for handling and utilizing the power and energy delivered hereunder. All service required by the Customer at each separate point of delivery served hereunder shall be furnished through one meter at, or compensated to, the available transmission voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$2,000.00
Demand Charges:	
Base Demand Charge	$9.30 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030.1
Conservation Charge	See Sheet No. 8.030.1
Non-Fuel Energy Charges:	
Base Energy Charge	1.074¢ per kWh
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's metering equipment for the 30-minute period of the Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE LARGE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: GSLDT-3

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose to any Customer who has service supplied at a transmission voltage of 69 kV or higher.

SERVICE:

Three phase, 60 hertz at the available transmission voltage of 69 kV or higher. The Customer will provide and maintain all transformers and related facilities necessary for handling and utilizing the power and energy delivered hereunder. All service required by the Customer at each separate point of delivery served hereunder shall be furnished through one meter at, or compensated to, the available transmission voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$2,000.00	
Demand Charges:		
Base Demand Charge	$9.30 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030.1	
Conservation Charge	See Sheet No. 8.030.1	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	1.227 ¢ per kWh	1.019 ¢ per kWh
Environmental Charge	See Sheet No. 8.030.1	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030.1	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand.

RATING PERIODS:

On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.553)

SPORTS FIELD SERVICE
(Closed Schedule)

RATE SCHEDULE: OS-2

AVAILABLE:

In all territory served.

APPLICATION:

This is a transitional rate available to municipal, county and school board accounts for the operation of a football, baseball or other playground, or civic or community auditorium, when all such service is taken at the available primary distribution voltage at a single point of delivery and measured through one meter, and who were active as of October 4, 1981. Customer may also elect to receive service from other appropriate rate schedules.

LIMITATION OF SERVICE:

Offices, concessions, businesses or space occupied by tenants, other than areas directly related to the operations above specified, are excluded hereunder and shall be separately served by the Company at utilization voltage. Not applicable when Rider TR is used.

MONTHLY RATE:

Customer Charge:	$125.00
Non-Fuel Energy Charges:	
Base Energy Charge	7.864 ¢ per kWh
Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum Charge:	$125.00

TERM OF SERVICE:

Pending termination by Florida Public Service Commission Order.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

METROPOLITAN TRANSIT SERVICE

RATE SCHEDULE: MET

AVAILABLE:

For electric service to Metropolitan Miami-Dade County Electric Transit System (METRORAIL) at each point of delivery required for the operation of an electric transit system on continuous and contiguous rights-of-way.

APPLICATION:

Service to be supplied will be three phase, 60 hertz and at the standard primary distribution voltage of 13,200 volts. All service required by Customer at each separate point of delivery served hereunder shall be furnished through one meter reflecting delivery at primary voltage. Resale of service is not permitted hereunder. Rider TR or a voltage discount is not applicable.

MONTHLY RATE:

Customer Charge:	$600.00
Demand Charges:	
Base Demand Charge	$12.70 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030.1
Conservation Charge	See Sheet No. 8.030.1
Non-Fuel Energy Charges:	
Base Energy Charge	1.693 ¢ per kWh
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand.

DEMAND:

The billing Demand is the kW, at each point of delivery, to the nearest whole kW, as determined from the Company's recording type metering equipment, for the period coincident with the 30-minute period of the electric rail transit system's greatest use supplied by the Company during the month adjusted for power factor.

BILLING:

Each point of delivery shall be separately billed according to the monthly charges as stated herein. All billing units related to charges under this rate schedule shall be determined from metering data on a monthly basis and determined for each point of delivery on the same monthly billing cycle day.

TERMS OF SERVICE

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective: January 1, 2018

(Continued from Sheet No. 8.650)

MONTHLY RATE:

Delivery Voltage Level	Distribution below 69 kV		69 kV & above
	CILC-1(G)	CILC-1(D)	CILC-1(T)
Maximum Demand Level	200-499 kW	500 kW & above	
Customer Charge:	$150.00	$250.00	$2,225.00
Demand Charges:			
Base Demand Charges:			
per kW of Maximum Demand	$4.00	$4.20	None
per kW of Load Control On-Peak Demand	$2.64	$3.00	$3.20
per kW of Firm On-Peak Demand	$10.00	$10.90	$11.70
Capacity Payment and Conservation Charge:			
CILC-1(G)	See Sheet No. 8.030.1		
CILC-1(D)	See Sheet No. 8.030.1		
CILC-1(T)	See Sheet No. 8.030.1		
Non-Fuel Energy Charges:			
Base Energy Charges:			
On-Peak Period charge per kWh	1.490 ¢	1.004 ¢	0.934 ¢
Off-Peak Period charge per kWh	1.490 ¢	1.004 ¢	0.934 ¢
Environmental Charge	See Sheet No. 8.030.1		
Additional Charges:			
Fuel Charge	See Sheet No. 8.030.1		
Storm Charge	See Sheet No. 8.040		
Franchise Fee	See Sheet No. 8.031		
Tax Clause	See Sheet No. 8.031		

Minimum: The Customer Charge plus the Base Demand Charges.

(Continued on Sheet No. 8.652)

160001 Hearing Exhibits 00448

COMMERCIAL/INDUSTRIAL DEMAND REDUCTION RIDER (CDR)
(OPTIONAL)

AVAILABLE:

In all territory served. Available to any commercial or industrial customer receiving service under Rate Schedules GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, or HLFT through the execution of a Commercial/Industrial Demand Reduction Rider Agreement in which the load control provisions of this rider can feasibly be applied.

LIMITATION OF AVAILABILITY:

This Rider may be modified or withdrawn subject to determinations made under Commission Rules 25-17.0021(4), F.A.C., Goals for Electric Utilities and 25-6.0438, F.A.C., Non-Firm Electric Service - Terms and Conditions or any other Commission determination.

APPLICATION:

For electric service provided to any commercial or industrial customer receiving service under Rate Schedule GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, or HLFT who as a part of the Commercial/Industrial Demand Reduction Rider Agreement between the Customer and the Company, agrees to allow the Company to control at least 200 kW of the Customer's load, or agrees to operate Backup Generation Equipment (see Definitions) and designate (if applicable) additional controllable demand to serve at least 200 kW of the Customer's own load during periods when the Company is controlling load. A Customer shall enter into a Commercial/Industrial Reduction Demand Rider Agreement with the Company to be eligible for this Rider. To establish the initial qualification for this Rider, the Customer must have had a Utility Controlled Demand during the summer Controllable Rating Period (April 1 through October 31) for at least three out of seven months of at least 200 kW greater than the Firm Demand level specified in Section 4 of the Commercial/Industrial Demand Reduction Rider Agreement. The Utility Controlled Demand shall not be served on a firm service basis until service has been terminated under this Rider.

LIMITATION OF SERVICE:

Customers participating in the General Service Load Management Program (FPL "Business On Call" Program) are not eligible for this Rider.

MONTHLY RATE:

All rates and charges under Rate Schedules GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, HLFT shall apply. In addition, the applicable Monthly Administrative Adder and Utility Controlled Demand Credit shall apply.

MONTHLY ADMINISTRATIVE ADDER:

Rate Schedule	Adder
GSD-1	$125.00
GSDT-1, HLFT (21-499 kW)	$125.00
GSLD-1, GSLDT-1, HLFT (500-1,999 kW)	$175.00
GSLD-2, GSLDT-2, HLFT (2,000 kW or greater)	$75.00
GSLD-3, GSLDT-3	$225.00

UTILITY CONTROLLED DEMAND CREDIT:

A monthly credit of ($8.20) per kW is allowed based on the Customer's Utility Controlled Demand.

UTILITY CONTROLLED DEMAND:

The Utility Controlled Demand for a month in which there are no load control events during the Controllable Rating Period shall be the sum of the Customer's kWh usage during the hours of the applicable Controllable Rating Period, divided by the total number of hours in the applicable Controllable Rating Period, less the Customer's Firm Demand.

In the event of Load Control occurring during the Controllable Rating Period, the Utility Controlled Demand shall be the sum of the Customer's kWh usage during the hours of the applicable Controllable Rating Period less the sum of the Customer's kWh usage during the Load Control Period, divided by the number of non-load control hours occurring during the applicable Controllable Rating Period, less the Customer's Firm Demand.

(Continued on Sheet No. 8.681)

160001 Hearing Exhibits 00449

(Continued from Sheet No. 8.715)

REMOVAL OF FACILITIES:

If Street Lighting facilities are removed either by Customer request or termination or breach of the agreement, the Customer shall pay FPL an amount equal to the original installed cost of the removed facilities less any salvage value and any depreciation (based on current depreciation rates as approved by the Florida Public Service Commission) plus removal cost.

MONTHLY RATE:

Luminaire Type		Lamp Size Initial Lumens/Watts		kWh/Mo. Estimate	Charge for FPL-Owned Unit ($) Fixtures	Maintenance	Energy Non-Fuel **	Total ***	Charge for Customer-Owned Unit $) **** Relamping/ Energy	Energy Only
High Pressure Sodium Vapor		6,300	70	29	$3.89	1.85	0.83	6.57	$2.69	$0.83
"	"	9,500	100	41	$3.96	1.86	1.18	7.00	$3.05	$1.18
"	"	16,000	150	60	$4.08	1.89	1.73	7.70	$3.63	$1.73
"	"	22,000	200	88	$6.18	2.41	2.53	11.12	$4.92	$2.53
"	"	50,000	400	168	$6.24	2.42	4.84	13.50	$7.24	$4.84
"	" *	27,500	250	116	$6.58	2.63	3.34	12.55	$5.94	$3.34
"	" *	140,000	1,000	411	$9.90	4.71	11.83	26.44	$16.58	$11.83
Mercury Vapor *		6,000	140	62	$3.07	1.66	1.78	6.51	$3.45	$1.78
"	" *	8,600	175	77	$3.12	1.66	2.22	7.00	$3.89	$2.22
"	" *	11,500	250	104	$5.21	2.40	2.99	10.60	$5.40	$2.99
"	" *	21,500	400	160	$5.18	2.36	4.61	12.15	$6.98	$4.61

* These units are closed to new FPL installations.
** The non-fuel energy charge is 2.879 ¢ per kWh.
*** Bills rendered based on "Total" charge. Unbundling of charges is not permitted.
**** New customer-owned facilities are closed to this rate effective January 1, 2017.

Charges for other FPL-owned facilities:

Wood pole used only for the street lighting system	$4.92
Concrete pole used only for the street lighting system	$6.74
Fiberglass pole used only for the street lighting system	$7.98
Steel pole used only for the street lighting system *	$6.74
Underground conductors not under paving	3.810 ¢ per foot
Underground conductors under paving	9.310 ¢ per foot

The Underground conductors under paving charge will not apply where a CIAC is paid pursuant to section "a)" under "Customer Contributions." The Underground conductors not under paving charge will apply in these situations.

(Continued on Sheet No. 8.717)

160001 Hearing Exhibits 00450

(Continued from Sheet No. 8.716)

On Customer-owned Street Lighting Systems, where Customer contracts to relamp at no cost to FPL, the Monthly Rate for non-fuel energy shall be 2.879 ¢ per kWh of estimated usage of each unit plus adjustments. On Street Lighting Systems, where the Customer elects to install Customer-owned monitoring systems, the Monthly Rate for non-fuel energy shall be 2.879 ¢ per kWh of estimated usage of each monitoring unit plus adjustments. The minimum monthly kWh per monitoring device will be 1 kilowatt-hour per month, and the maximum monthly kWh per monitoring device will be 5 kilowatt-hours per month.

During the initial installation period:
Facilities in service for 15 days or less will not be billed;
Facilities in service for 16 days or more will be billed for a full month.

WILLFUL DAMAGE:

Upon the **second** occurrence of willful damage to any FPL-owned facilities, the Customer will be responsible for the cost incurred for repair or replacement. If the lighting fixture is damaged, based on prior written instructions from the Customer, FPL will:

a) Replace the fixture with a shielded cutoff cobrahead. The Customer shall pay $280.00 for the shield plus all associated costs. However, if the Customer chooses to have the shield installed after the first occurrence, the Customer shall only pay the $280.00 cost of the shield; or

b) Replace with a like unshielded fixture. For this, and each subsequent occurrence, the Customer shall pay the costs specified under "Removal of Facilities"; or

c) Terminate service to the fixture.

Option selection shall be made by the Customer in writing and apply to all fixtures which FPL has installed on the Customer's behalf. Selection changes may be made by the Customer at any time and will become effective ninety (90) days after written notice is received.

Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

SPECIAL CONDITIONS:

Customers whose lights are turned off during sea turtle nesting season will receive a credit equal to the fuel charges associated with the fixtures that are turned off.

TERM OF SERVICE:

Initial term of ten (10) years with automatic, successive five (5) year extensions unless terminated in writing by either FPL or the Customer at least ninety (90) days prior to the current term's expiration.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

160001 Hearing Exhibits 00451

STREET LIGHTING METERED SERVICE

RATE SCHEDULE: SL-1M

AVAILABLE:

In all territory served.

APPLICATION:

For customer-owned lighting of streets and roadways, whether public or private, which are thoroughfares for normal flow of vehicular traffic. Lighting for other applications such as: municipally and privately-owned parking lots; parks and recreational areas; or any other area not expressly defined above, is not permitted under this schedule.

SERVICE:

Single phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$14.00
Non-Fuel Energy Charges:	
Base Energy Charge	2.827 ¢ per kWh
Conservation Charge	See Sheet No. 8.030
Capacity Payment Charge	See Sheet No. 8.030
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum:	$14.00

TERM OF SERVICE:

Not less than one (1) year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

PREMIUM LIGHTING

RATE SCHEDULE: PL-1

AVAILABLE:

In all territory served.

APPLICATION:

FPL-owned lighting facilities not available under rate schedule SL-1 and OL-1. To any Customer for the sole purpose of lighting streets, roadways and common areas, other than individual residential locations. This includes but is not limited to parking lots, homeowners association common areas, or parks.

SERVICE:

Service will be unmetered and will include lighting installation, lamp replacement and facilities maintenance for FPL-owned lighting systems. It will also include energy from dusk each day until dawn the following day.

The Company, while exercising reasonable diligence at all times to furnish service hereunder, does not guarantee continuous lighting and will not be liable for damages for any interruption, deficiency or failure of service, and reserves the right to interrupt service at any time for necessary repairs to lines or equipment.

LIMITATION OF SERVICE:

Installation shall be made only when, in the judgement of the Company, the location and the type of the facilities are, and will continue to be, easily and economically accessible to the Company equipment and personnel for both construction and maintenance.

Stand-by, non-firm, or resale service is not permitted hereunder.

TERM OF SERVICE:

The term of service is (20) twenty years. At the end of the term of service, the Customer may elect to execute a new agreement based on the current estimated replacement costs. The Company will retain ownership of these facilities.

FACILITIES PAYMENT OPTION:

The Customer will pay for the facilities in a lump sum in advance of construction. The amount will be the Company's total work order cost for these facilities times the Present Value Revenue Requirement (PVRR) multiplier of 1.1961. Monthly Maintenance and Energy charges will apply for the term of service.

FACILITIES SELECTION:

Facilities selection shall be made by the Customer in writing by executing the Company's Premium Lighting Agreement.

(Continued on Sheet No. 8.721)

160001 Hearing Exhibits 00453

(Continued from Sheet No. 8.720)

MONTHLY RATE :

Facilities:

Paid in full:	Monthly rate is zero, for Customer's who have executed a Premium Lighting Agreement before March 1, 2010:
10 years payment option:	1.362% of total work order cost.
20 years payment option:	0.925% of total work order cost.
Maintenance:	FPL's estimated costs of maintaining lighting facilities.
Billing:	FPL reserves the right to assess a charge for the recovery of any dedicated billing system developed solely for this rate.
Energy:	KWH Consumption for fixtures shall be estimated using the following formula:

$$KWH = \frac{\text{Unit Wattage (usage)} \times 353.3 \text{ hours per month}}{1000}$$

Non-Fuel Energy	2.879 ¢/kWh
Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

During the initial installation period:
Facilities in service for 15 days or less will not be billed;
Facilities in service for 16 days or more will be billed for a full month.

MINIMUM MONTHLY BILL:

The minimum monthly bill shall be the applicable Facilities Maintenance and Billing charges.

(Continued on Sheet No. 8.722)

160001 Hearing Exhibits 00454

(Continued from Sheet No. 8.721)

EARLY TERMINATION:

If the Customer no longer wishes to receive service under this schedule, the Customer may terminate the Premium Lighting Agreement by giving at least (90) ninety days advance written notice to the Company. Upon early termination of service, the Customer shall pay an amount computed by applying the following Termination Factors to the installed cost of the facilities, based on the year in which the Agreement was terminated. These Termination Factors will not apply to Customers who elected to pay for the facilities in a lump sum in lieu of a monthly payment.

FPL may also charge the Customer for the cost to the utility for removing the facilities.

Ten (10) Years Payment Option	Termination Factor	Twenty (20) Years Payment Option	Termination Factor
1	1.2100	1	1.2100
2	1.0410	2	1.0934
3	0.9588	3	1.0679
4	0.8698	4	1.0403
5	0.7733	5	1.0104
6	0.6688	6	0.9781
7	0.5556	7	0.9430
8	0.4329	8	0.9050
9	0.3000	9	0.8638
10	0.1560	10	0.8192
>10	0.0000	11	0.7709
		12	0.7185
		13	0.6618
		14	0.6004
		15	0.5338
		16	0.4616
		17	0.3835
		18	0.2988
		19	0.2071
		20	0.1077
		>20	0.0000

WILLFUL DAMAGE:

In the event of willful damage to these facilities, FPL will provide the initial repair of each installed item at its expense. Upon the second occurrence of willful damage, and subsequent occurrence to these FPL-owned facilities, the Customer will be responsible for the cost for repair or replacement.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

OUTDOOR LIGHTING

RATE SCHEDULE OL-1

AVAILABLE:

In all territory served.

APPLICATION:

For year-round outdoor security lighting of yards, walkways and other areas. Lights to be served hereunder shall be at locations which are easily and economically accessible to Company vehicles and personnel for construction and maintenance.

It is intended that Company-owned security lights will be installed on existing Company-owned electric facilities, or short extension thereto, in areas where a street lighting system is not provided or is not sufficient to cover the security lighting needs of a particular individual or location. Where more extensive security lighting is required, such as for large parking lots or other commercial areas, the Customer will provide the fixtures, supports and connecting wiring; the Company will connect to the Customer's system and provide the services indicated below.

SERVICE:

Service includes lamp renewals, energy from approximately dusk each day until approximately dawn the following day, and maintenance of Company-owned facilities. The Company will replace all burned-out lamps and will maintain its facilities during regular daytime working hours as soon as practicable following notification by the Customer that such work is necessary. The Company shall be permitted to enter the Customer's premises at all reasonable times for the purpose of inspecting, maintaining, installing and removing any or all of its equipment and facilities.

The Company, while exercising reasonable diligence at all times to furnish service hereunder, does not guarantee continuous lighting and will not be liable for damages for any interruption, deficiency or failure of service, and reserves the right to interrupt service at any time for necessary repairs to lines or equipment.

LIMITATION OF SERVICE:

This schedule is not available for service normally supplied on the Company's standard street lighting schedules. Company-owned facilities will be installed only on Company-owned poles. Customer-owned facilities will be installed only on Customer-owned poles. Overhead conductors will not be installed in any area designated as an underground distribution area, or any area, premises or location served from an underground source. Customer must have an active house or premise account associated with this service. Stand-by or resale service not permitted hereunder.

MONTHLY RATE:

Luminaire Type		Lamp Size Initial Lumens/Watts		KWH/Mo. Estimate	Charge for Company-Owned Unit ($) Fixtures	Maintenance	Energy Non-Fuel **	Total	Charge for Customer-Owned Unit ($) Relamping/ Energy	Energy Only
High Pressure Sodium Vapor		6,300	70	29	$5.05	$1.90	$0.89	7.84	$2.74	$0.89
"	"	9,500	100	41	$5.16	$1.90	$1.26	8.32	$3.11	$1.26
"	"	16,000	150	60	$5.34	$1.93	$1.84	9.11	$3.72	$1.84
"	"	22,000	200	88	$7.77	$2.49	$2.70	12.96	$5.13	$2.70
"	"	50,000	400	168	$8.27	$2.45	$5.16	15.88	$7.55	$5.16
"	" *	12,000	150	60	$5.34	$1.93	$1.84	9.11	$3.99	$1.84
Mercury Vapor *		6,000	140	62	$3.88	$1.70	$1.91	7.49	$3.57	$1.91
"	" *	8,600	175	77	$3.90	$1.70	$2.37	7.97	$4.03	$2.37
"	" *	21,500	400	160	$6.39	$2.40	$4.92	13.71	$7.26	$4.92

* These units are closed to new Company installations.

** The non-fuel energy charge is 3.073 ¢ per kWh.

(Continued on Sheet No. 8.726)

160001 Hearing Exhibits 00456

(Continued from Sheet No. 8.725)

Charges for other Company-owned facilities:

Wood pole and span of conductors:	$11.14
Concrete pole and span of conductors:	$15.04
Fiberglass pole and span of conductors:	$17.68
Steel pole used only for the street lighting system *	$15.04
Underground conductors (excluding trenching)	$0.085 per foot
Down-guy, Anchor and Protector	$10.13

For Customer-owned outdoor lights, where the Customer contracts to relamp at no cost to FPL, the monthly rate for non-fuel energy shall be $3.073¢ per kWh of estimated usage of each unit plus adjustments.

Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Clause	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

TERM OF SERVICE:

Not less than one year. In the event the Company installs any facilities for which there is an added monthly charge, the Term of Service shall be for not less than three years.

If the Customer terminates service before the expiration of the initial term of the agreement, the Company may require reimbursement for the total expenditures made to provide such service, plus the cost of removal of the facilities installed less the salvage value thereof, and less credit for all monthly payments made for Company-owned facilities.

WILLFUL DAMAGE:

In the event of willful damage to these facilities, FPL will provide the initial repair of each installed item at its expense. Upon the second occurrence of willful damage, and subsequent occurrence to these FPL-owned facilities, the Customer will be responsible for the cost for repair or replacement.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

COMPANY-OWNED FACILITIES:

Company-owned luminaires normally will be mounted on Company's existing distribution poles and served from existing overhead wires. The Company will provide one span of secondary conductor from existing secondary facilities to a Company-owned light at the Company's expense. When requested by the Customer, and at the option of the Company, additional spans of wire or additional poles or underground conductors may be installed by the Company upon agreement by the Customer to use the facilities for a minimum of three years and pay each month the charges specified under MONTHLY RATE.

MONTHLY RATE

The Customer will make a lump sum payment for the cost of changes in the height of existing poles or the installation of additional poles in the Company's distribution lines or the cost of any other facilities required for the installation of lights to be served hereunder.

(Continued on Sheet No. 8.727)

160001 Hearing Exhibits 00457

RECREATIONAL LIGHTING

(Closed Schedule)

RATE SCHEDULE: RL-1

AVAILABLE:

In all territory served. Available to any customer, who, as of January 16, 2001, was either taking service pursuant to this schedule or had a fully executed Recreational Lighting Agreement with the Company.

APPLICATION:

For FPL-owned facilities for the purpose of lighting community recreational areas. This includes, but is not limitied to, baseball, softball, football, soccer, tennis, and basketball.

SERVICE:

Service will be metered and will include lighting installation, lamp replacement and facilities maintenance for FPL-owned lighting systems.

The Company, while exercising reasonable diligence at all times to furnish service hereunder, does not guarantee continuous lighting and will not be liable for damages for any interruption, deficiency or failure of service, and reserves the right to interrupt service at any time for necessary repairs to lines or equipment.

LIMITATION OF SERVICE:

Installation shall be made only when, in the judgement of the Company, the location and the type of the facilities are, and will continue to be, easily and economically accessible to the Company equipment and personnel for both construction and maintenance.

Stand-by, non-firm, or resale service is not permitted hereunder.

TERM OF SERVICE:

The term of service is (20) twenty years. At the end of the term of service, the Customer may elect to execute a new Agreement based on the current estimated replacement costs. The Company will retain ownership of these facilities.

FACILITIES PAYMENT OPTION:

The Customer will pay for the facilities in a lump sum in advance of construction. The amount will be the Company's total work order cost for these facilities times the Present Value Revenue Requirement (PVRR) multiplier of 1.1961. Monthly Maintenance and energy charges will apply for the term of service.

FACILITIES SELECTION:

Facilities selection shall be made by the Customer in writing by executing the Company's Recreational Lighting Agreement.

(Continued on Sheet No. 8.744)

160001 Hearing Exhibits 00458

(Continued from Sheet No. 8.743)

MONTHLY RATE :

Facilities:

Paid in full:	Monthly rate is zero.
10 years payment option:	1.364% of total work order cost.*
20 years payment option:	0.926% of total work order cost.*

* Both (10) ten and (20) twenty year payment options are closed to new service, and are only available for the duration of the term of service of those customers that have fully executed a Recreational Lighting Agreement with the Company before January 16, 2001.

Maintenance:	FPL's estimated costs of maintaining lighting facilities.
Billing:	FPL reserves the right to assess a charge for the recovery of any dedicated billing system developed solely for this rate.
Charge Per Month:	Company's otherwise applicable general service rate schedule.
Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

MINIMUM MONTHLY BILL:

As provided in the otherwise applicable rate schedule, plus the Facilities Maintenance and Billing charges.

(Continued on Sheet No. 8.745)

160001 Hearing Exhibits 00459

(Continued from Sheet No. 8.744)

EARLY TERMINATION:

If the Customer no longer wishes to receive service under this schedule, the Customer may terminate the Recreational Lighting Agreement by giving at least (90) ninety days advance written notice to the Company. Upon early termination of service, the Customer shall pay an amount computed by applying the following Termination Factors to the installed cost of the facilities, based on the year in which the Agreement was terminated. These Termination Factors will not apply to Customers who elected to pay for the facilities in a lump sum in lieu of a monthly payment.

FPL may also charge the Customer for the cost to the utility for removing the facilities.

Ten (10) Years Payment Option	Termination Factor	Twenty (20) Years Payment Option	Termination Factor
1	1.2100	1	1.2100
2	1.0410	2	1.0934
3	0.9588	3	1.0679
4	0.8698	4	1.0403
5	0.7733	5	1.0104
6	0.6688	6	0.9781
7	0.5556	7	0.9430
8	0.4329	8	0.9050
9	0.3000	9	0.8638
10	0.1560	10	0.8192
>10	0.0000	11	0.7709
		12	0.7185
		13	0.6618
		14	0.6004
		15	0.5338
		16	0.4616
		17	0.3835
		18	0.2988
		19	0.2071
		20	0.1077
		>20	0.0000

WILLFUL DAMAGE:

In the event of willful damage to these facilities, FPL will provide the initial repair of each installed item at its expense. Upon the second occurrence of willful damage, and subsequent occurrence to these FPL-owned facilities, the Customer will be responsible for the cost for repair or replacement.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

160001 Hearing Exhibits 00460

STANDBY AND SUPPLEMENTAL SERVICE

RATE SCHEDULE: SST-1

AVAILABLE:

In all territory served by the Company. Service under this rate schedule is on a customer by customer basis subject to the completion of arrangements necessary for implementation.

APPLICATION:

For electric service to any Customer, at a point of delivery, whose electric service requirements for the Customer's load are supplied or supplemented from the Customer's generation equipment at that point of service and require standby and/or supplemental service. For purposes of determining applicability of this rate schedule, the following definitions shall be used:

(1) "Standby Service" means electric energy or capacity supplied by the Company to replace energy or capacity ordinarily generated by the Customer's own generation equipment during periods of either scheduled (maintenance) or unscheduled (backup) outages of all or a portion of the Customer's generation.

(2) "Supplemental Service" means electric energy or capacity supplied by the Company in addition to that which is normally provided by the Customer's own generation equipment.

A Customer is required to take service under this rate schedule if the Customer's total generation capacity is more than 20% of the Customer's total electrical load and the Customer's generators are not for emergency purposes only.

Customers taking service under this rate schedule shall enter into a Standby and Supplemental Service Agreement ("Agreement"); however, failure to execute such an agreement will not pre-empt the application of this rate schedule for service.

SERVICE:

Three phase, 60 hertz, and at the available standard voltage. All service supplied by the Company shall be furnished through one metering point. Resale of service is not permitted hereunder.

Transformation Rider - TR, Sheet No. 8.820, does not apply to Standby Service.

MONTHLY RATE:

STANDBY SERVICE

Delivery Voltage:	Below 69 kV			69kV & Above
Contract Standby Demand:	SST-1(D1) Below 500 kW	SST-1(D2) 500 to 1,999 kW	SST-1(D3) 2,000 kW & Above	SST-1(T) All Levels
Customer Charge:	$125.00	$125.00	$425.00	$1,800.00
Demand Charges:				
Base Demand Charges:				
Distribution Demand Charge per kW of Contract Standby Demand	$3.00	$3.00	$3.00	N/A
Reservation Demand Charge per kW	$1.48	$1.48	$1.48	$1.35
Daily Demand Charge per kW for each daily maximum On-Peak Standby Demand	$0.70	$0.70	$0.70	$0.44
Capacity Payment and Conservation Charges	See Sheet No. 8.030.1			

(Continued on Sheet No. 8.751)

160001 Hearing Exhibits 00461

(Continued from Sheet No. 8.750)

Delivery Voltage:	Below 69 kV			69 kV & Above
	SST-1(D1)	SST-1(D2)	SST-1(D3)	SST-1(T)
Contract Standby Demand:	Below 500 kW	500 to 1,999 kW	2,000 kW & Above	All Levels
Non-Fuel Energy Charges:				
Base Energy Charges:				
On-Peak Period charge per kWh	0.711 ¢	0.711 ¢	0.711 ¢	0.707 ¢
Off-Peak Period charge per kWh	0.711 ¢	0.711 ¢	0.711 ¢	0.707 ¢

Environmental Charge — See Sheet No. 8.030.1

Additional Charges:
- Fuel Charge — See Sheet No. 8.030.1
- Storm Charge — See Sheet No. 8.040
- Franchise Fee — See Sheet No. 8.031
- Tax Clause — See Sheet No. 8.031

Minimum: The Customer Charge plus the Base Demand Charges.

DEMAND CALCULATION:

The Demand Charge for Standby Service shall be (1) the charge for Distribution Demand **plus** (2) the greater of the sum of the Daily Demand Charges **or** the Reservation Demand Charge times the maximum On-Peak Standby Demand actually registered during the month **plus** (3) the Reservation Demand Charge times the difference between the Contract Standby Demand and the maximum On-Peak Standby Demand actually registered during the month.

SUPPLEMENTAL SERVICE

Supplemental Service shall be the total power supplied by the Company minus the Standby Service supplied by the Company during the same metering period. The charge for all Supplemental Service shall be calculated by applying the applicable retail rate schedule, excluding the customer charge.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

CONTRACT STANDBY DEMAND:

The level of Customer's generation requiring Standby Service as specified in the Agreement. This Contract Standby Demand will not be less than the maximum load actually served by the Customer's generation during the current month or prior 23-month period less the amount specified as the Customer's load which would not have to be served by the Company in the event of an outage of the Customer's generation equipment. For a Customer receiving only Standby Service as identified under Special Provisions, the Contract Standby Demand shall be maximum load actually served by the Company during the current month or prior 23-month period.

A Customer's Contract Standby Demand may be re-established to allow for the following adjustments:

1. Demand reduction resulting from the installation of FPL Demand Side Management Measures or FPL Research Project efficiency measures; or

(Continued on Sheet No. 8.752)

160001 Hearing Exhibits 00462

INTERRUPTIBLE STANDBY AND SUPPLEMENTAL SERVICE
(OPTIONAL)

RATE SCHEDULE: ISST-1

AVAILABLE:

In all territory served by the Company. Service under this rate schedule is on a customer by customer basis subject to the completion of arrangements necessary for implementation.

LIMITATION OF AVAILABILITY:

This schedule may be modified or withdrawn subject to determinations made under Commission Rule 25-6.0438, F.A.C., Non-Firm Electric Service - Terms and Conditions or any other Commission determination.

APPLICATION:

A Customer who is eligible to receive service under the Standby and Supplemental Service (SST-1) rate schedule may, as an option, take service under this rate schedule, unless the Customer has entered into a contract to sell firm capacity and/or energy to the Company, and the Customer cannot restart its generation equipment without power supplied by the Company, in which case the Customer may only receive Standby and Supplemental Service under the Company's SST-1 rate schedule.

Customers taking service under this rate schedule shall enter into an Interruptible Standby and Supplemental Service Agreement ("Agreement"). This interruptible load shall not be served on a firm service basis until service has been terminated under this rate schedule.

SERVICE:

Three phase, 60 hertz, and at the available standard voltage.

A designated portion of the Customer's load served under this schedule is subject to interruption by the Company. Transformation Rider-TR, where applicable, shall only apply to the Customer's Contract Standby Demand for delivery voltage below 69 kV. Resale of service is not permitted hereunder.

MONTHLY RATE:

STANDBY SERVICE Delivery Voltage:		Distribution Below 69 kV ISST-1(D)	Transmission 6 9 kV & Above ISST-1(T)
Customer Charge:		$425.00	$1,800.00
Demand Charges:			
Base Demand Charges:			
Distribution Demand Charge per kW of Contract Standby Demand		$3.00	N/A
Reservation Demand Charge per kW of Interruptible Standby Demand		$0.26	$0.30
Reservation Demand Charge per kW of Firm Standby Demand		$1.48	$1.35
Daily Demand Charge per kW for each daily maximum On-Peak Interruptible Standby Demand		$0.70	$0.44
Daily Demand Charge per kW for each daily maximum On-Peak Firm Standby Demand		$0.13	$0.12
Capacity Payment and Conservation Charges	See Sheet No. 8.030.1		
Non-Fuel Energy Charges:			
Base Energy Charges:			
On-Peak Period charge per kWh		0.711 ¢	0.707 ¢
Off-Peak Period charge per kWh		0.711 ¢	0.707 ¢
Environmental Charge	See Sheet No. 8.030.1		

(Continued on Sheet No. 8.761)

160001 Hearing Exhibits 00463

SEASONAL DEMAND – TIME OF USE RIDER – SDTR
(OPTIONAL)

RIDER: SDTR

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW. This is an optional rate available to customers otherwise served under the GSD-1 GSDT-1, GSLD-1, GSLDT-1, GSLD-2 or GSLDT-2 Rate Schedules.

SERVICE:
Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:
OPTION A: Non-Seasonal Standard Rate

Annual Maximum Demand	SDTR-1 21-499 kW	SDTR-2 500-1,999 kW	SDTR-3 2,000 kW or greater
Customer Charge:	$25.00	$75.00	$225.00
Demand Charges:			
Seasonal On-peak Demand Charge Per kW of Seasonal On-peak Demand	$10.40	$11.90	$12.46
Non-Seasonal Demand Charge Per kW of Non- Seasonal Maximum Demand	$9.00	$11.30	$11.78
Capacity Payment Charge:	See Sheet No. 8.030		
Conservation Charge:	See Sheet No. 8.030		
Energy Charges:			
Base Seasonal On-Peak Per kWh of Seasonal On-Peak Energy	8.334 ¢	5.896 ¢	4.681 ¢
Base Seasonal Off-Peak Per kWh of Seasonal Off-Peak Energy	1.503 ¢	1.196 ¢	1.169 ¢
Base Non-Seasonal Energy Charge Per kWh of Non-Seasonal Energy	2.096 ¢	1.657 ¢	1.493 ¢
Environmental Charge:	See Sheet No. 8.030		
Additional Charges:			
Fuel Charge:	See Sheet No. 8.030		
Storm Charge:	See Sheet No. 8.040		
Franchise Fee:	See Sheet No. 8.031		
Tax Clause:	See Sheet No. 8.031		

(Continued from Sheet No. 8.830)

OPTION B: Non-Seasonal Time of Use Rate

Annual Maximum Demand	SDTR-1 21-499 kW	SDTR-2 500-1,999 kW	SDTR-3 2,000 kW or greater
Customer Charge:	$25.00	$75.00	$225.00
Demand Charges:			
Seasonal On-peak Demand Charge Per kW of Seasonal On-peak Demand	$10.40	$11.90	$12.46
Non-Seasonal Demand Charge Per kW of Non- Seasonal Peak Demand	$9.00	$11.30	$11.78
Capacity Payment Charge	See Sheet No. 8.030		
Conservation Charge	See Sheet No. 8.030		
Energy Charges:			
Base Seasonal On-Peak Per kWh of Seasonal On-Peak Energy	8.334 ¢	5.896 ¢	4.681 ¢
Base Seasonal Off-Peak Per kWh of Seasonal Off-Peak Energy	1.503 ¢	1.196 ¢	1.169 ¢
Base Non-Seasonal On-Peak Per kWh of Non-Seasonal On-Peak Energy	4.762 ¢	3.529 ¢	3.223 ¢
Base Non-Seasonal Off-Peak Per kWh of Non-Seasonal Off-Peak Energy	1.503 ¢	1.196 ¢	1.169 ¢
Environmental Charge	See Sheet No. 8.030		
Additional Charges:			
Fuel Charge	See Sheet No. 8.030		
Storm Charge	See Sheet No. 8.040		
Franchise Fee	See Sheet No. 8.031		
Tax Clause	See Sheet No. 8.031		

Minimum Charge: The Customer Charge plus the currently effective Demand Charges.

NON-SEASONAL RATING PERIODS (OPTION B only):

Non-Seasonal On-Peak Period:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through May 31 and October 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day.

Non-Seasonal Off-Peak Period:

All other hours.

(Continued On Sheet No. 8.832)

160001 Hearing Exhibits 00465

Appendix A

Distribution Substation Facilities
Monthly Rental and Termination Factors

The Monthly Rental Factor to be applied to the in-place value of the Distribution Substation Facilities as identified in the Long-Term Rental Agreement is as follows:

	Monthly Rental Factor
Distribution Substation Facilities	1.33%

Termination Fee for Initial 20 Year Period

If the Long-Term Rental Agreement for Distribution Substation Facilities is terminated by Customer during the Initial Term, Customer shall pay to Company a Termination Fee, such fee shall be computed by applying the following Termination Factors to the in-place value of the Facilities based on the year in which the Agreement is terminated:

Year Agreement Is Terminated	Termination Factors %	Year Agreement Is Terminated	Termination Factors %	Year Agreement Is Terminated	Termination Factors %
1	3.36	8	11.16	15	6.01
2	6.03	9	10.88	16	4.88
3	8.03	10	10.40	17	3.70
4	9.47	11	9.76	18	2.48
5	10.42	12	8.98	19	1.25
6	10.98	13	8.08	20	0.00
7	11.21	14	7.08		

Termination Fee for Subsequent Extension Periods

If the Long-Term Rental Agreement for Distribution Substation Facilities is terminated by Customer during an Extension, Customer shall pay to Company a Termination Fee, such fee shall be computed based on the net present value of the remaining payments under the extension period by applying the Termination Factor based on the month terminated to the monthly rental payment amount.

Month Terminated	Termination Factor	Month Terminated	Termination Factor	Month Terminated	Termination Factor	Month Terminated	Termination Factor
1	49.902	16	39.177	31	27.361	46	14.343
2	49.219	17	38.424	32	26.531	47	13.429
3	48.531	18	37.667	33	25.697	48	12.510
4	47.839	19	36.904	34	24.857	49	11.584
5	47.143	20	36.137	35	24.012	50	10.653
6	46.442	21	35.365	36	23.161	51	9.715
7	45.736	22	34.587	37	22.304	52	8.772
8	45.026	23	33.805	38	21.442	53	7.822
9	44.311	24	33.017	39	20.575	54	6.866
10	43.592	25	32.225	40	19.702	55	5.904
11	42.868	26	31.427	41	18.823	56	4.936
12	42.139	27	30.624	42	17.938	57	3.962
13	41.406	28	29.816	43	17.048	58	2.981
14	40.668	29	29.003	44	16.152	59	1.994
15	39.925	30	28.185	45	15.250	60	1.000

EXHIBIT D

FLORIDA POWER AND LIGHT COMPANY

SUMMARY OF STIPULATED DEPRECIATION PARAMETERS, ANNUAL DEPRECIATION ACCRUALS, RATES AND THEORETICAL RESERVE IMBALANCES AS OF DECEMBER 31, 2016

	ANNUAL DEPRECIATION ACCRUALS FILED IN SECOND NOIA (1)	STIPULATED PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE (4)	ANNUAL DEPRECIATION ACCRUALS (5)	ANNUAL DEPRECIATION RATE (6)	INCREASE/ (DECREASE) (7)=(5)-(1)	THEORETICAL RESERVE IMBALANCE (8)
STEAM PRODUCTION PLANT								
MANATEE STEAM PLANT								
MANATEE COMMON								
311 STRUCTURES AND IMPROVEMENTS	3,555,569	06-2028	80 - R2 *	(1)	3,555,569	3.17	-	6,912,427
312 BOILER PLANT EQUIPMENT	587,612	06-2028	50 - S0 *	(2)	587,612	7.62	-	(716,232)
314 TURBOGENERATOR UNITS	194,743	06-2028	55 - R0.5 *	(1)	194,743	2.02	-	1,576,347
315 ACCESSORY ELECTRIC EQUIPMENT	225,626	06-2028	65 - S0 *	(2)	225,626	2.34	-	711,438
316 MISCELLANEOUS POWER PLANT EQUIPMENT	50,889	06-2028	65 - R0.5 *	(1)	50,889	2.08	-	318,559
TOTAL MANATEE COMMON	*4,614,439*				*4,614,439*	*3.26*	-	*8,802,540*
MANATEE UNIT 1								
311 STRUCTURES AND IMPROVEMENTS	118,728	06-2028	80 - R2 *	(1)	118,728	1.74	-	451,713
312 BOILER PLANT EQUIPMENT	8,412,866	06-2028	50 - S0 *	(2)	8,412,866	4.64	-	2,758,122
314 TURBOGENERATOR UNITS	2,925,448	06-2028	55 - R0.5 *	(1)	2,925,448	4.03	-	2,326,693
315 ACCESSORY ELECTRIC EQUIPMENT	586,631	06-2028	65 - S0 *	(2)	586,631	4.11	-	762,157
316 MISCELLANEOUS POWER PLANT EQUIPMENT	153,580	06-2028	65 - R0.5 *	(1)	153,580	3.91	-	12,890
TOTAL MANATEE UNIT 1	*12,197,253*				*12,197,253*	*4.37*	-	*6,311,575*
MANATEE UNIT 2								
311 STRUCTURES AND IMPROVEMENTS	91,383	06-2028	80 - R2 *	(1)	91,383	1.83	-	304,218
312 BOILER PLANT EQUIPMENT	9,170,501	06-2028	50 - S0 *	(2)	9,170,501	4.99	-	(853,378)
314 TURBOGENERATOR UNITS	2,629,560	06-2028	55 - R0.5 *	(1)	2,629,560	3.72	-	2,657,742
315 ACCESSORY ELECTRIC EQUIPMENT	549,410	06-2028	65 - S0 *	(2)	549,410	4.48	-	525,153
316 MISCELLANEOUS POWER PLANT EQUIPMENT	165,589	06-2028	65 - R0.5 *	(1)	165,589	4.79	-	(141,189)
TOTAL MANATEE UNIT 2	*12,606,443*				*12,606,443*	*4.58*	-	*2,492,545*
TOTAL MANATEE STEAM PLANT	***29,418,135***				***29,418,135***	***4.23***	-	***17,606,660***
MARTIN STEAM PLANT								
MARTIN COMMON								
311 STRUCTURES AND IMPROVEMENTS	6,108,878	06-2031	80 - R2 *	(1)	6,108,878	2.52	-	1,576,814
312 BOILER PLANT EQUIPMENT	314,305	06-2031	50 - S0 *	(2)	314,305	4.45	-	(16,312)
314 TURBOGENERATOR UNITS	955,816	06-2031	55 - R0.5 *	(1)	955,816	3.48	-	120,584
315 ACCESSORY ELECTRIC EQUIPMENT	367,628	06-2031	65 - S0 *	(2)	367,628	3.57	-	182,673
316 MISCELLANEOUS POWER PLANT EQUIPMENT	147,308	06-2031	65 - R0.5 *	(1)	147,308	3.79	-	(55,709)
TOTAL MARTIN COMMON	*7,893,935*				*7,893,935*	*2.72*	-	*1,808,049*
MARTIN PIPELINE								
312 BOILER PLANT EQUIPMENT	-	06-2031	50 - S0 *	0	-	0.00	-	146,044
TOTAL MARTIN PIPELINE	-				-		-	*146,044*
MARTIN UNIT 1								
311 STRUCTURES AND IMPROVEMENTS	439,660	06-2031	80 - R2 *	(1)	439,660	2.68	-	(338,710)
312 BOILER PLANT EQUIPMENT	9,632,706	06-2031	50 - S0 *	(2)	9,632,706	4.53	-	(11,114,702)
314 TURBOGENERATOR UNITS	3,018,863	06-2031	55 - R0.5 *	(1)	3,018,863	3.35	-	3,533,638
315 ACCESSORY ELECTRIC EQUIPMENT	760,833	06-2031	65 - S0 *	(2)	760,833	3.12	-	1,117,936
316 MISCELLANEOUS POWER PLANT EQUIPMENT	136,913	06-2031	65 - R0.5 *	(1)	136,913	3.81	-	(1,083)
TOTAL MARTIN UNIT 1	*13,988,975*				*13,988,975*	*4.03*	-	*(6,802,922)*
MARTIN UNIT 2								
311 STRUCTURES AND IMPROVEMENTS	269,000	06-2031	80 - R2 *	(1)	269,000	2.39	-	16,379
312 BOILER PLANT EQUIPMENT	9,993,557	06-2031	50 - S0 *	(2)	9,993,557	4.64	-	(12,113,493)
314 TURBOGENERATOR UNITS	3,967,632	06-2031	55 - R0.5 *	(1)	3,967,632	4.79	-	(6,413,222)
315 ACCESSORY ELECTRIC EQUIPMENT	819,853	06-2031	65 - S0 *	(2)	819,853	3.56	-	1,155,353
316 MISCELLANEOUS POWER PLANT EQUIPMENT	141,426	06-2031	65 - R0.5 *	(1)	141,426	4.31	-	(145,922)
TOTAL MARTIN UNIT 2	*15,191,468*				*15,191,468*	*4.53*	-	*(17,500,907)*

TOTAL MARTIN STEAM PLANT	***37,074,378***			***37,074,378***	***3.81***	***-***	***(22,349,736)***

FLORIDA POWER AND LIGHT COMPANY

SUMMARY OF STIPULATED DEPRECIATION PARAMETERS, ANNUAL DEPRECIATION ACCRUALS, RATES AND THEORETICAL RESERVE IMBALANCES AS OF DECEMBER 31, 2016

	ANNUAL DEPRECIATION ACCRUALS FILED IN SECOND NOIA	STIPULATED PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	STIPULATED ANNUAL DEPRECIATION ACCRUALS	STIPULATED ANNUAL DEPRECIATION RATE	INCREASE/ (DECREASE)	THEORETICAL RESERVE IMBALANCE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(1)	(8)
SCHERER STEAM PLANT								
SCHERER COAL CARS								
312 BOILER PLANT EQUIPMENT	-	06-2052	50 - S0 *	0	-	0.00	-	21,225,391
TOTAL SCHERER COAL CARS	-				-	*0.00*	-	*21,225,391*
SCHERER COMMON								
311 STRUCTURES AND IMPROVEMENTS	882,796	06-2052	80 - R2 *	(2)	593,363	1.51	(289,433)	5,991,729
312 BOILER PLANT EQUIPMENT	765,628	06-2052	50 - S0 *	(7)	575,215	2.23	(190,413)	2,404,237
314 TURBOGENERATOR UNITS	128,042	06-2052	55 - R0.5 *	(2)	90,212	2.08	(37,830)	375,639
315 ACCESSORY ELECTRIC EQUIPMENT	29,480	06-2052	65 - S0 *	(6)	21,081	1.72	(8,399)	174,774
316 MISCELLANEOUS POWER PLANT EQUIPMENT	95,718	06-2052	65 - R0.5 *	(2)	66,001	1.80	(29,717)	526,401
TOTAL SCHERER COMMON	*1,901,664*				*1,345,872*	*1.81*	*(555,792)*	*9,472,779*
SCHERER COMMON UNIT 3 AND 4								
311 STRUCTURES AND IMPROVEMENTS	64,127	06-2052	80 - R2 *	(2)	43,238	1.44	(20,889)	474,125
312 BOILER PLANT EQUIPMENT	695,012	06-2052	50 - S0 *	(7)	518,337	2.32	(176,675)	2,000,180
314 TURBOGENERATOR UNITS	128,216	06-2052	55 - R0.5 *	(2)	87,575	3.09	(40,641)	22,182
315 ACCESSORY ELECTRIC EQUIPMENT	125,025	06-2052	65 - S0 *	(6)	84,836	3.01	(40,189)	15,549
TOTAL SCHERER COMMON UNIT 3 AND 4	*1,012,380*				*733,986*	*2.37*	*(278,394)*	*2,512,036*
SCHERER UNIT 4								
311 STRUCTURES AND IMPROVEMENTS	5,539,441	06-2052	80 - R2 *	(2)	3,657,321	2.30	(1,882,120)	4,235,503
312 BOILER PLANT EQUIPMENT	25,810,174	06-2052	50 - S0 *	(7)	18,753,594	2.79	(7,056,580)	11,623,684
314 TURBOGENERATOR UNITS	3,290,441	06-2052	55 - R0.5 *	(2)	2,326,903	1.89	(963,538)	16,466,913
315 ACCESSORY ELECTRIC EQUIPMENT	1,775,494	06-2052	65 - S0 *	(6)	1,229,541	2.49	(545,953)	1,679,029
316 MISCELLANEOUS POWER PLANT EQUIPMENT	140,274	06-2052	65 - R0.5 *	(2)	96,228	1.88	(44,046)	918,553
TOTAL SCHERER UNIT 4	*36,555,824*				*26,063,587*	*2.59*	*(10,492,237)*	*34,923,682*
TOTAL SCHERER STEAM PLANT	***39,469,868***				***28,143,445***	***2.45***	***(11,326,423)***	***68,133,888***

FLORIDA POWER AND LIGHT COMPANY

SUMMARY OF STIPULATED DEPRECIATION PARAMETERS, ANNUAL DEPRECIATION ACCRUALS, RATES AND THEORETICAL RESERVE IMBALANCES AS OF DECEMBER 31, 2016

	ANNUAL DEPRECIATION ACCRUALS FILED IN SECOND NOIA (1)	STIPULATED PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE (4)	ANNUAL DEPRECIATION ACCRUALS (5)	ANNUAL DEPRECIATION RATE (6)	INCREASE/ (DECREASE) (7)=(5)-(1)	THEORETICAL RESERVE IMBALANCE (8)
SJRPP STEAM PLANT								
SJRPP COAL AND LIMESTONE								
311 STRUCTURES AND IMPROVEMENTS	86,954	06-2052	80 - R2 *	(2)	56,376	1.58	(30,578)	263,397
312 BOILER PLANT EQUIPMENT	936,645	06-2052	50 - S0 *	(7)	695,857	2.25	(240,788)	1,254,762
315 ACCESSORY ELECTRIC EQUIPMENT	92,938	06-2052	65 - S0 *	(6)	64,527	1.71	(28,411)	410,022
316 MISCELLANEOUS POWER PLANT EQUIPMENT	7,319	06-2052	65 - R0.5 *	(2)	4,919	1.64	(2,400)	34,342
TOTAL SJRPP COAL AND LIMESTONE	*1,123,856*				*821,679*	*2.13*	*(302,177)*	*1,962,523*
SJRPP COAL CARS								
312 BOILER PLANT EQUIPMENT	-	06-2052	50 - S0 *	0	-	0.00	-	29,301
TOTAL SJRPP COAL CARS	-				-	*0.00*	-	*29,301*
SJRPP COMMON								
311 STRUCTURES AND IMPROVEMENTS	550,442	06-2052	80 - R2 *	(2)	360,631	1.09	(189,811)	8,190,705
312 BOILER PLANT EQUIPMENT	70,207	06-2052	50 - S0 *	(7)	53,339	1.44	(16,868)	989,192
314 TURBOGENERATOR UNITS	44,693	06-2052	55 - R0.5 *	(2)	31,278	1.25	(13,415)	647,424
315 ACCESSORY ELECTRIC EQUIPMENT	107,750	06-2052	65 - S0 *	(6)	75,674	1.30	(32,076)	1,394,046
316 MISCELLANEOUS POWER PLANT EQUIPMENT	31,157	06-2052	65 - R0.5 *	(2)	20,925	1.31	(10,232)	409,432
TOTAL SJRPP COMMON	*804,249*				*541,847*	*1.16*	*(262,402)*	*11,630,798*
SJRPP GYPSUM AND ASH								
311 STRUCTURES AND IMPROVEMENTS	52,212	06-2052	80 - R2 *	(2)	33,886	1.56	(18,326)	205,821
312 BOILER PLANT EQUIPMENT	463,038	06-2052	50 - S0 *	(7)	347,177	2.03	(115,861)	1,530,537
315 ACCESSORY ELECTRIC EQUIPMENT	1,188	06-2052	65 - S0 *	(6)	820	1.56	(368)	9,484
316 MISCELLANEOUS POWER PLANT EQUIPMENT	4,680	06-2052	65 - R0.5 *	(2)	3,101	2.00	(1,579)	15,045
TOTAL SJRPP GYPSUM AND ASH	*521,118*				*384,984*	*1.98*	*(136,134)*	*1,760,887*
SJRPP UNIT 1								
311 STRUCTURES AND IMPROVEMENTS	129,202	06-2052	80 - R2 *	(2)	85,423	0.94	(43,779)	2,406,640
312 BOILER PLANT EQUIPMENT	2,887,403	06-2052	50 - S0 *	(7)	2,109,002	2.12	(778,401)	11,909,807
314 TURBOGENERATOR UNITS	860,365	06-2052	55 - R0.5 *	(2)	585,314	1.86	(275,051)	5,624,850
315 ACCESSORY ELECTRIC EQUIPMENT	261,684	06-2052	65 - S0 *	(6)	182,170	1.46	(79,514)	2,563,726
316 MISCELLANEOUS POWER PLANT EQUIPMENT	34,392	06-2052	65 - R0.5 *	(2)	23,269	1.14	(11,123)	567,013
TOTAL SJRPP UNIT 1	*4,173,046*				*2,985,178*	*1.93*	*(1,187,868)*	*23,072,036*
SJRPP UNIT 2								
311 STRUCTURES AND IMPROVEMENTS	153,341	06-2052	80 - R2 *	(2)	99,985	1.39	(53,356)	871,467
312 BOILER PLANT EQUIPMENT	2,923,057	06-2052	50 - S0 *	(7)	2,122,077	2.35	(800,980)	5,215,006
314 TURBOGENERATOR UNITS	940,874	06-2052	55 - R0.5 *	(2)	636,580	2.24	(304,294)	2,123,689
315 ACCESSORY ELECTRIC EQUIPMENT	269,617	06-2052	65 - S0 *	(6)	185,613	1.84	(84,004)	903,366
316 MISCELLANEOUS POWER PLANT EQUIPMENT	36,931	06-2052	65 - R0.5 *	(2)	24,815	1.58	(12,116)	232,661
TOTAL SJRPP UNIT 2	*4,323,820*				*3,069,070*	*2.23*	*(1,254,750)*	*9,346,189*
TOTAL SJRPP STEAM PLANT	***10,946,089***				***7,802,758***	***1.97***	***(3,143,331)***	***47,801,734***
TOTAL STEAM PRODUCTION	**116,908,468**				**102,438,706**	***3.19***	**(14,469,754)**	**111,192,530**

FLORIDA POWER AND LIGHT COMPANY

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	ANNUAL DEPRECIATION ACCRUALS FILED IN SECOND NOIA	STIPULATED PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	STIPULATED ANNUAL DEPRECIATION ACCRUALS	STIPULATED ANNUAL DEPRECIATION RATE	INCREASE/ (DECREASE)	THEORETICAL RESERVE IMBALANCE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(1)	(8)
NUCLEAR PRODUCTION PLANT								
ST. LUCIE NUCLEAR PLANT								
ST. LUCIE COMMON								
321 STRUCTURES AND IMPROVEMENTS	8,926,161	04-2043	100 - R1.5 *	(1)	8,926,161	2.25	-	806,865
322 REACTOR PLANT EQUIPMENT	1,066,835	04-2043	60 - R1 *	(2)	1,066,835	1.92	-	13,797,249
323 TURBOGENERATOR UNITS	895,663	04-2043	45 - R0.5 *	0	895,663	7.22	-	(10,379,459)
324 ACCESSORY ELECTRIC EQUIPMENT	719,133	04-2043	75 - R2.5 *	(1)	719,133	2.09	-	628,019
325 MISCELLANEOUS POWER PLANT EQUIPMENT	841,331	04-2043	50 - R1.5 *	(3)	841,331	4.06	-	(5,352,295)
TOTAL ST. LUCIE COMMON	*12,449,123*				*12,449,123*	*2.39*	-	*(499,621)*
ST. LUCIE UNIT 1								
321 STRUCTURES AND IMPROVEMENTS	5,176,105	03-2036	100 - R1.5 *	(1)	5,176,105	2.66	-	1,908,657
322 REACTOR PLANT EQUIPMENT	31,180,373	03-2036	60 - R1 *	(2)	31,180,373	3.72	-	(3,253,051)
323 TURBOGENERATOR UNITS	21,057,503	03-2036	45 - R0.5 *	0	21,057,503	5.11	-	(44,607,633)
324 ACCESSORY ELECTRIC EQUIPMENT	3,830,023	03-2036	75 - R2.5 *	(1)	3,830,023	3.20	-	(3,451,360)
325 MISCELLANEOUS POWER PLANT EQUIPMENT	293,754	03-2036	50 - R1.5 *	(3)	293,754	2.59	-	(32,991)
TOTAL ST. LUCIE UNIT 1	*61,537,758*				*61,537,758*	*3.90*	-	*(49,436,378)*
ST. LUCIE UNIT 2								
321 STRUCTURES AND IMPROVEMENTS	6,772,839	04-2043	100 - R1.5 *	(1)	6,772,839	2.27	-	(7,401,205)
322 REACTOR PLANT EQUIPMENT	28,986,146	04-2043	60 - R1 *	(2)	28,986,146	2.75	-	40,230,190
323 TURBOGENERATOR UNITS	13,521,840	04-2043	45 - R0.5 *	0	13,521,840	3.86	-	(27,949,423)
324 ACCESSORY ELECTRIC EQUIPMENT	4,291,331	04-2043	75 - R2.5 *	(1)	4,291,331	2.27	-	(7,020,267)
325 MISCELLANEOUS POWER PLANT EQUIPMENT	657,629	04-2043	50 - R1.5 *	(3)	657,629	2.73	-	(1,439,469)
TOTAL ST. LUCIE UNIT 2	*54,229,785*				*54,229,785*	*2.83*	-	*(3,580,174)*
TOTAL ST. LUCIE NUCLEAR PLANT	***128,216,666***				***128,216,666***	***3.20***	-	***(53,516,173)***
TURKEY POINT NUCLEAR PLANT								
TURKEY POINT COMMON								
321 STRUCTURES AND IMPROVEMENTS	11,259,224	04-2033	100 - R1.5 *	(1)	11,259,224	3.13	-	27,007,106
322 REACTOR PLANT EQUIPMENT	7,469,106	04-2033	60 - R1 *	(2)	7,469,106	5.43	-	(12,296,879)
323 TURBOGENERATOR UNITS	1,101,765	04-2033	45 - R0.5 *	0	1,101,765	5.05	-	(659,806)
324 ACCESSORY ELECTRIC EQUIPMENT	1,264,143	04-2033	75 - R2.5 *	(1)	1,264,143	2.36	-	7,573,071
325 MISCELLANEOUS POWER PLANT EQUIPMENT	1,366,579	04-2033	50 - R1.5 *	(3)	1,366,579	3.67	-	2,657,008
TOTAL TURKEY POINT COMMON	*22,460,817*				*22,460,817*	*3.68*	-	*24,280,499*
TURKEY POINT UNIT 3								
321 STRUCTURES AND IMPROVEMENTS	9,592,385	07-2032	100 - R1.5 *	(1)	9,592,385	5.23	-	(18,893,418)
322 REACTOR PLANT EQUIPMENT	28,968,915	07-2032	60 - R1 *	(2)	28,968,915	4.94	-	(40,997,937)
323 TURBOGENERATOR UNITS	46,846,514	07-2032	45 - R0.5 *	0	46,846,514	6.20	-	(90,005,300)
324 ACCESSORY ELECTRIC EQUIPMENT	5,207,015	07-2032	75 - R2.5 *	(1)	5,207,015	3.46	-	(303,387)
325 MISCELLANEOUS POWER PLANT EQUIPMENT	1,038,166	07-2032	50 - R1.5 *	(3)	1,038,166	6.62	-	(3,493,346)
TOTAL TURKEY POINT UNIT 3	*91,652,995*				*91,652,995*	*5.42*	-	*(153,693,387)*
TURKEY POINT UNIT 4								
321 STRUCTURES AND IMPROVEMENTS	5,009,472	04-2033	100 - R1.5 *	(1)	5,009,472	3.90	-	(1,705,762)
322 REACTOR PLANT EQUIPMENT	21,983,244	04-2033	60 - R1 *	(2)	21,983,244	4.28	-	594,567
323 TURBOGENERATOR UNITS	34,673,611	04-2033	45 - R0.5 *	0	34,673,611	5.78	-	(45,478,058)
324 ACCESSORY ELECTRIC EQUIPMENT	4,585,745	04-2033	75 - R2.5 *	(1)	4,585,745	2.62	-	10,489,559
325 MISCELLANEOUS POWER PLANT EQUIPMENT	782,083	04-2033	50 - R1.5 *	(3)	782,083	6.55	-	(3,513,949)
TOTAL TURKEY POINT UNIT 4	*67,034,155*				*67,034,155*	*4.69*	-	*(39,613,643)*
TOTAL TURKEY POINT NUCLEAR PLANT	***181,147,967***				***181,147,967***	***4.85***	-	***(169,026,531)***
TOTAL NUCLEAR PRODUCTION PLANT	**309,364,633**				**309,364,633**	***4.00***	-	**(222,542,704)**

FLORIDA POWER AND LIGHT COMPANY

SUMMARY OF STIPULATED DEPRECIATION PARAMETERS, ANNUAL DEPRECIATION ACCRUALS, RATES AND THEORETICAL RESERVE IMBALANCES AS OF DECEMBER 31, 2016

	ANNUAL DEPRECIATION ACCRUALS FILED IN SECOND NOIA	STIPULATED PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	STIPULATED ANNUAL DEPRECIATION ACCRUALS	STIPULATED ANNUAL DEPRECIATION RATE	INCREASE/ (DECREASE)	THEORETICAL RESERVE IMBALANCE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(1)	(8)
COMBINED CYCLE PRODUCTION PLANT								
LAUDERDALE COMBINED CYCLE PLANT								
LAUDERDALE COMMON								
341 STRUCTURES AND IMPROVEMENTS	1,864,990	06-2033	80 - R2 *	(2)	1,864,990	2.20	-	13,180,814
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	355,978	06-2033	50 - R1.5 *	(3)	355,978	3.09	-	1,151,170
343 PRIME MOVERS - GENERAL	1,408,857	06-2033	50 - R1 *	(3)	1,408,857	5.20	-	2,008,848
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	2,412,721	06-2033	9 - L0 *	35	2,412,721	6.42	-	2,467,301
344 GENERATORS	18,609	06-2033	60 - R2 *	(3)	18,609	2.73	-	105,541
345 ACCESSORY ELECTRIC EQUIPMENT	194,238	06-2033	50 - R2.5 *	(2)	194,238	1.60	-	2,443,702
346 MISCELLANEOUS POWER PLANT EQUIPMENT	42,255	06-2033	50 - S0.5 *	(2)	42,255	3.42	-	110,079
TOTAL LAUDERDALE COMMON	*6,297,648*				*6,297,648*	*3.60*	-	*21,467,454*
LAUDERDALE UNIT 4								
341 STRUCTURES AND IMPROVEMENTS	106,647	06-2033	80 - R2 *	(2)	106,647	2.09	-	796,327
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	11,997	06-2033	50 - R1.5 *	(3)	11,997	1.78	-	155,012
343 PRIME MOVERS - GENERAL	4,990,638	06-2033	50 - R1 *	(3)	4,990,638	4.11	-	(8,295,388)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	4,923,007	06-2033	9 - L0 *	35	4,923,007	7.66	-	(1,440,800)
344 GENERATORS	582,531	06-2033	60 - R2 *	(3)	582,531	2.02	-	4,817,881
345 ACCESSORY ELECTRIC EQUIPMENT	724,053	06-2033	50 - R2.5 *	(2)	724,053	2.43	-	3,597,979
346 MISCELLANEOUS POWER PLANT EQUIPMENT	50,337	06-2033	50 - S0.5 *	(2)	50,337	1.94	-	492,662
TOTAL LAUDERDALE UNIT 4	*11,389,210*				*11,389,210*	*4.51*	-	*123,672*
LAUDERDALE UNIT 5								
341 STRUCTURES AND IMPROVEMENTS	81,765	06-2033	80 - R2 *	(2)	81,765	2.55	-	396,015
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	16,959	06-2033	50 - R1.5 *	(3)	16,959	2.28	-	150,637
343 PRIME MOVERS - GENERAL	6,093,158	06-2033	50 - R1 *	(3)	6,093,158	5.00	-	(23,704,681)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	1,947,066	06-2033	9 - L0 *	35	1,947,066	8.06	-	(1,194,387)
344 GENERATORS	644,016	06-2033	60 - R2 *	(3)	644,016	2.03	-	6,181,174
345 ACCESSORY ELECTRIC EQUIPMENT	641,836	06-2033	50 - R2.5 *	(2)	641,836	2.58	-	2,889,119
346 MISCELLANEOUS POWER PLANT EQUIPMENT	37,579	06-2033	50 - S0.5 *	(2)	37,579	2.08	-	313,871
TOTAL LAUDERDALE UNIT 5	*9,462,379*				*9,462,379*	*4.54*	-	*(14,968,252)*
TOTAL LAUDERDALE COMBINED CYCLE PLANT	***27,149,237***				***27,149,237***	***4.27***	-	***6,622,873***

FLORIDA POWER AND LIGHT COMPANY

SUMMARY OF STIPULATED DEPRECIATION PARAMETERS, ANNUAL DEPRECIATION ACCRUALS, RATES AND THEORETICAL RESERVE IMBALANCES AS OF DECEMBER 31, 2016

	ANNUAL DEPRECIATION ACCRUALS FILED IN SECOND NOIA	STIPULATED						
		PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	INCREASE/ (DECREASE)	THEORETICAL RESERVE IMBALANCE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(1)	(8)
FT. MYERS COMBINED CYCLE PLANT								
FT. MYERS COMMON								
341 STRUCTURES AND IMPROVEMENTS	274,099	06-2043	80 - R2 *	(2)	274,099	3.11	-	(1,368,305)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	34,287	06-2043	50 - R1.5 *	(3)	34,287	4.32	-	(256,438)
343 PRIME MOVERS - GENERAL	115,845	06-2043	50 - R1 *	(3)	115,845	3.12	-	587,725
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	9,562	06-2043	9 - L0 *	35	9,562	2.17	-	130,099
344 GENERATORS	8,706	06-2043	60 - R2 *	(3)	8,706	3.77	-	(6,554)
345 ACCESSORY ELECTRIC EQUIPMENT	42,018	06-2043	50 - R2.5 *	(2)	42,018	3.61	-	(23,340)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	25,678	06-2043	50 - S0.5 *	(2)	25,678	3.34	-	(62,417)
TOTAL FT. MYERS COMMON	*510,195*				*510,195*	*3.20*	-	*(999,229)*
FT. MYERS UNIT 2								
341 STRUCTURES AND IMPROVEMENTS	673,825	06-2043	80 - R2 *	(2)	673,825	2.34	-	2,236,099
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	188,313	06-2043	50 - R1.5 *	(3)	188,313	3.04	-	(221,250)
343 PRIME MOVERS - GENERAL	12,726,738	06-2043	50 - R1 *	(3)	12,726,738	3.46	-	(8,508,684)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	22,432,118	06-2043	9 - L0 *	35	22,432,118	7.42	-	(4,209,929)
344 GENERATORS	1,601,297	06-2043	60 R2 *	(3)	1,601,297	2.80	-	1,543,232
345 ACCESSORY ELECTRIC EQUIPMENT	1,299,735	06-2043	50 R2.5 *	(2)	1,299,735	2.34	-	5,763,223
346 MISCELLANEOUS POWER PLANT EQUIPMENT	86,528	06-2043	50 S0.5 *	(2)	86,528	2.44	-	372,341
TOTAL FT. MYERS UNIT 2	*39,008,554*				*39,008,554*	*4.75*	-	*(3,024,967)*
FT. MYERS UNIT 3								
341 STRUCTURES AND IMPROVEMENTS	353,027	06-2043	80 - R2 *	(2)	353,027	3.38	-	405,434
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	480,063	06-2043	50 - R1.5 *	(3)	480,063	3.58	-	597,988
343 PRIME MOVERS - GENERAL	7,453,192	06-2043	50 - R1 *	(3)	7,453,192	4.54	-	(20,637,101)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	794,452	06-2043	25 - R1 *	29	794,452	3.94	-	(2,919,226)
344 GENERATORS	1,622,599	06-2043	60 - R2 *	(3)	1,622,599	3.46	-	1,872,418
345 ACCESSORY ELECTRIC EQUIPMENT	1,119,474	06-2043	50 - R2.5 *	(2)	1,119,474	3.40	-	1,534,052
346 MISCELLANEOUS POWER PLANT EQUIPMENT	63,488	06-2043	50 - S0.5 *	(2)	63,488	3.66	-	20,761
TOTAL FT. MYERS UNIT 3	*11,886,295*				*11,886,295*	*4.10*	-	*(19,125,674)*
TOTAL FT. MYERS COMBINED CYCLE PLANT	***51,405,044***				***51,405,044***	***4.56***	-	***(23,149,870)***
MANATEE COMBINED CYCLE PLANT								
MANATEE UNIT 3								
341 STRUCTURES AND IMPROVEMENTS	685,908	06-2045	80 - R2 *	(2)	685,908	2.37	-	2,430,311
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	104,158	06-2045	50 - R1.5 *	(3)	104,158	2.60	-	337,686
343 PRIME MOVERS - GENERAL	7,925,106	06-2045	50 - R1 *	(3)	7,925,106	3.35	-	(15,339,053)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	11,522,442	06-2045	9 - L0 *	35	11,522,442	7.88	-	(6,317,202)
344 GENERATORS	986,460	06-2045	60 - R2 *	(3)	986,460	2.38	-	4,287,442
345 ACCESSORY ELECTRIC EQUIPMENT	1,123,207	06-2045	50 - R2.5 *	(2)	1,123,207	2.49	-	3,744,141
346 MISCELLANEOUS POWER PLANT EQUIPMENT	304,322	06-2045	50 - S0.5 *	(2)	304,322	2.77	-	413,799
TOTAL MANATEE UNIT 3	*22,651,603*				*22,651,603*	*4.41*	-	*(10,442,875)*
TOTAL MANATEE COMBINED CYCLE PLANT	***22,651,603***				***22,651,603***	***4.41***	-	***(10,442,875)***

FLORIDA POWER AND LIGHT COMPANY

SUMMARY OF STIPULATED DEPRECIATION PARAMETERS, ANNUAL DEPRECIATION ACCRUALS, RATES AND THEORETICAL RESERVE IMBALANCES AS OF DECEMBER 31, 2016

		ANNUAL DEPRECIATION ACCRUALS FILED IN SECOND NOIA	STIPULATED PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	STIPULATED ANNUAL DEPRECIATION ACCRUALS	STIPULATED ANNUAL DEPRECIATION RATE	INCREASE/ (DECREASE)	THEORETICAL RESERVE IMBALANCE
		(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(1)	(8)
MARTIN COMBINED CYCLE PLANT									
	MARTIN COMMON								
341	STRUCTURES AND IMPROVEMENTS	1,108,391	06-2034	80 - R2 *	(2)	1,108,391	2.24	-	7,695,449
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	115,248	06-2034	50 - R1.5 *	(3)	115,248	2.42	-	794,968
343	PRIME MOVERS - GENERAL	583,469	06-2034	50 - R1 *	(3)	583,469	2.56	-	5,308,538
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	113,005	06-2034	9 - L0 *	35	113,005	5.07	-	291,414
345	ACCESSORY ELECTRIC EQUIPMENT	108,474	06-2034	50 - R2.5 *	(2)	108,474	2.04	-	895,943
346	MISCELLANEOUS POWER PLANT EQUIPMENT	97,030	06-2034	50 - S0.5 *	(2)	97,030	2.31	-	599,395
	TOTAL MARTIN COMMON	*2,125,617*				*2,125,617*	*2.40*	-	*15,585,707*
	MARTIN UNIT 3								
341	STRUCTURES AND IMPROVEMENTS	33,127	06-2034	80 - R2 *	(2)	33,127	2.00	-	278,599
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	3,631	06-2034	50 - R1.5 *	(3)	3,631	2.03	-	31,820
343	PRIME MOVERS - GENERAL	6,831,770	06-2034	50 - R1 *	(3)	6,831,770	4.49	-	(16,857,749)
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	5,203,640	06-2034	9 - L0 *	35	5,203,640	7.69	-	(1,774,195)
344	GENERATORS	884,322	06-2034	60 - R2 *	(3)	884,322	3.33	-	1,781,851
345	ACCESSORY ELECTRIC EQUIPMENT	766,155	06-2034	50 - R2.5 *	(2)	766,155	2.69	-	2,990,764
346	MISCELLANEOUS POWER PLANT EQUIPMENT	11,362	06-2034	50 - S0.5 *	(2)	11,362	1.99	-	99,233
	TOTAL MARTIN UNIT 3	*13,734,007*				*13,734,007*	*4.95*	-	*(13,449,678)*
	MARTIN UNIT 4								
341	STRUCTURES AND IMPROVEMENTS	43,868	06-2034	80 - R2 *	(2)	43,868	2.93	-	110,833
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	3,628	06-2034	50 - R1.5 *	(3)	3,628	2.03	-	31,662
343	PRIME MOVERS - GENERAL	6,184,204	06-2034	50 - R1 *	(3)	6,184,204	3.92	-	1,427,872
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	7,313,830	06-2034	9 - L0 *	35	7,313,830	7.27	-	332,518
344	GENERATORS	984,180	06-2034	60 - R2 *	(3)	984,180	3.00	-	3,473,631
345	ACCESSORY ELECTRIC EQUIPMENT	703,261	06-2034	50 - R2.5 *	(2)	703,261	2.75	-	2,542,533
346	MISCELLANEOUS POWER PLANT EQUIPMENT	26,313	06-2034	50 - S0.5 *	(2)	26,313	3.18	-	83,023
	TOTAL MARTIN UNIT 4	*15,259,284*				*15,259,284*	*4.78*	-	*8,002,072*
	MARTIN UNIT 8								
341	STRUCTURES AND IMPROVEMENTS	573,956	06-2045	80 - R2 *	(2)	573,956	2.42	-	1,740,002
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	307,851	06-2045	50 - R1.5 *	(3)	307,851	2.70	-	649,515
343	PRIME MOVERS - GENERAL	8,618,573	06-2045	50 - R1 *	(3)	8,618,573	3.37	-	(15,752,681)
343.2	PRIME MOVERS - CAPITAL SPARE PARTS	16,547,744	06-2045	9 - L0 *	35	16,547,744	7.76	-	(7,879,796)
344	GENERATORS	1,085,630	06-2045	60 - R2 *	(3)	1,085,630	2.64	-	1,463,661
345	ACCESSORY ELECTRIC EQUIPMENT	1,350,717	06-2045	50 - R2.5 *	(2)	1,350,717	2.61	-	2,246,098
346	MISCELLANEOUS POWER PLANT EQUIPMENT	130,427	06-2045	50 - S0.5 *	(2)	130,427	2.66	-	392,180
	TOTAL MARTIN UNIT 8	*28,614,898*				*28,614,898*	*4.75*	-	*(17,141,019)*
TOTAL MARTIN COMBINED CYCLE PLANT		***59,733,806***				***59,733,806***	***4.64***	-	***(7,002,918)***

FLORIDA POWER AND LIGHT COMPANY

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	ANNUAL DEPRECIATION ACCRUALS FILED IN SECOND NOIA	STIPULATED						
		PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	INCREASE/ (DECREASE)	THEORETICAL RESERVE IMBALANCE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(1)	(8)
SANFORD COMBINED CYCLE PLANT								
SANFORD COMMON								
341 STRUCTURES AND IMPROVEMENTS	1,716,821	06-2043	80 - R2 *	(2)	1,716,821	2.40	-	2,810,957
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	2,071	06-2043	50 - R1.5 *	(3)	2,071	2.33	-	12,533
343 PRIME MOVERS - GENERAL	472,457	06-2043	50 - R1 *	(3)	472,457	7.96	-	(6,242,667)
344 GENERATORS	6,733	06-2043	60 - R2 *	(3)	6,733	3.36	-	2,551
345 ACCESSORY ELECTRIC EQUIPMENT	65,499	06-2043	50 - R2.5 *	(2)	65,499	3.06	-	(4,233)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	62,776	06-2043	50 - S0.5 *	(2)	62,776	2.81	-	132,322
TOTAL SANFORD COMMON	*2,326,357*				*2,326,357*	*2.83*	-	*(3,288,537)*
SANFORD UNIT 4								
341 STRUCTURES AND IMPROVEMENTS	177,306	06-2043	80 - R2 *	(2)	177,306	2.39	-	39,312
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	45,212	06-2043	50 - R1.5 *	(3)	45,212	2.51	-	204,895
343 PRIME MOVERS - GENERAL	7,881,392	06-2043	50 - R1 *	(3)	7,881,392	4.00	-	(36,421,891)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	12,100,700	06-2043	9 - L0 *	35	12,100,700	8.64	-	(13,793,063)
344 GENERATORS	948,518	06-2043	60 - R2 *	(3)	948,518	2.89	-	551,991
345 ACCESSORY ELECTRIC EQUIPMENT	877,843	06-2043	50 - R2.5 *	(2)	877,843	2.49	-	2,661,455
346 MISCELLANEOUS POWER PLANT EQUIPMENT	85,878	06-2043	50 - S0.5 *	(2)	85,878	2.58	-	284,150
TOTAL SANFORD UNIT 4	*22,116,849*				*22,116,849*	*5.30*	-	*(46,473,151)*
SANFORD UNIT 5								
341 STRUCTURES AND IMPROVEMENTS	175,968	06-2042	80 - R2 *	(2)	175,968	2.42	-	138,092
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	44,326	06-2042	50 - R1.5 *	(3)	44,326	2.44	-	228,545
343 PRIME MOVERS - GENERAL	8,861,157	06-2042	50 - R1 *	(3)	8,861,157	4.12	-	(40,254,192)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	10,840,519	06-2042	9 - L0 *	35	10,840,519	8.58	-	(11,996,188)
344 GENERATORS	916,971	06-2042	60 - R2 *	(3)	916,971	2.81	-	1,222,969
345 ACCESSORY ELECTRIC EQUIPMENT	888,158	06-2042	50 - R2.5 *	(2)	888,158	2.56	-	2,350,940
346 MISCELLANEOUS POWER PLANT EQUIPMENT	76,835	06-2042	50 - S0.5 *	(2)	76,835	2.65	-	227,504
TOTAL SANFORD UNIT 5	*21,803,934*				*21,803,934*	*5.18*	-	*(48,082,329)*
TOTAL SANFORD COMBINED CYCLE PLANT	***46,247,140***				***46,247,140***	***5.03***	-	***(97,844,018)***
TURKEY POINT COMBINED CYCLE PLANT								
TURKEY POINT UNIT 5								
341 STRUCTURES AND IMPROVEMENTS	752,952	06-2047	80 - R2 *	(2)	752,952	2.33	-	3,210,854
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	321,432	06-2047	50 - R1.5 *	(3)	321,432	2.59	-	1,164,769
343 PRIME MOVERS - GENERAL	8,229,929	06-2047	50 - R1 *	(3)	8,229,929	3.28	-	(14,994,797)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	9,957,555	06-2047	9 - L0 *	35	9,957,555	7.77	-	(4,898,714)
344 GENERATORS	1,117,299	06-2047	60 - R2 *	(3)	1,117,299	2.68	-	1,091,000
345 ACCESSORY ELECTRIC EQUIPMENT	1,305,917	06-2047	50 - R2.5 *	(2)	1,305,917	2.51	-	3,885,392
346 MISCELLANEOUS POWER PLANT EQUIPMENT	342,605	06-2047	50 - S0.5 *	(2)	342,605	2.76	-	554,336
TOTAL TURKEY POINT UNIT 5	*22,027,689*				*22,027,689*	*4.16*	-	*(9,987,160)*
TOTAL TURKEY POINT COMBINED CYCLE PLANT	***22,027,689***				***22,027,689***	***4.16***	-	***(9,987,160)***

FLORIDA POWER AND LIGHT COMPANY

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	ANNUAL DEPRECIATION ACCRUALS FILED IN SECOND NOIA	STIPULATED PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	STIPULATED ANNUAL DEPRECIATION ACCRUALS	STIPULATED ANNUAL DEPRECIATION RATE	INCREASE/ (DECREASE)	THEORETICAL RESERVE IMBALANCE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(1)	(8)
WEST COUNTY COMBINED CYCLE PLANT								
WEST COUNTY COMMON								
341 STRUCTURES AND IMPROVEMENTS	81,539	06-2051	80 - R2 *	(2)	81,539	2.61	-	75,878
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	13,013	06-2051	50 - R1.5 *	(3)	13,013	2.89	-	6,565
343 PRIME MOVERS - GENERAL	1,017,642	06-2051	50 - R1 *	(3)	1,017,642	3.26	-	(288,349)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	9,518,547	06-2051	9 - L0 *	35	9,518,547	7.51	-	(2,640,014)
345 ACCESSORY ELECTRIC EQUIPMENT	37,670	06-2051	50 - R2.5 *	(2)	37,670	2.92	-	(1,299)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	24,471	06-2051	50 - S0.5 *	(2)	24,471	2.93	-	10,083
TOTAL WEST COUNTY COMMON	*10,692,882*				*10,692,882*	*6.53*	-	*(2,837,137)*
WEST COUNTY UNIT 1								
341 STRUCTURES AND IMPROVEMENTS	2,950,294	06-2049	80 - R2 *	(2)	2,950,294	2.69	-	(197,859)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	686,716	06-2049	50 - R1.5 *	(3)	686,716	3.15	-	(1,208,926)
343 PRIME MOVERS - GENERAL	11,786,189	06-2049	50 - R1 *	(3)	11,786,189	3.92	-	(72,800,566)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	9,668,171	06-2049	9 - L0 *	35	9,668,171	11.80	-	(23,511,414)
344 GENERATORS	1,422,168	06-2049	60 - R2 *	(3)	1,422,168	2.87	-	(1,438,981)
345 ACCESSORY ELECTRIC EQUIPMENT	2,062,857	06-2049	50 - R2.5 *	(2)	2,062,857	2.85	-	(1,563,213)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	243,367	06-2049	50 - S0.5 *	(2)	243,367	3.03	-	(256,755)
TOTAL WEST COUNTY UNIT 1	*28,819,762*				*28,819,762*	*4.47*	-	*(100,977,715)*
WEST COUNTY UNIT 2								
341 STRUCTURES AND IMPROVEMENTS	1,098,055	06-2049	80 - R2 *	(2)	1,098,055	2.77	-	(1,092,938)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	256,957	06-2049	50 - R1.5 *	(3)	256,957	3.44	-	(970,511)
343 PRIME MOVERS - GENERAL	8,710,947	06-2049	50 - R1 *	(3)	8,710,947	3.41	-	(25,525,671)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	13,722,028	06-2049	9 - L0 *	35	13,722,028	9.16	-	(17,954,488)
344 GENERATORS	1,260,888	06-2049	60 - R2 *	(3)	1,260,888	2.89	-	(1,451,501)
345 ACCESSORY ELECTRIC EQUIPMENT	955,908	06-2049	50 - R2.5 *	(2)	955,908	2.88	-	(996,792)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	366,491	06-2049	50 - S0.5 *	(2)	366,491	3.08	-	(402,841)
TOTAL WEST COUNTY UNIT 2	*26,371,274*				*26,371,274*	*4.87*	-	*(48,394,742)*
WEST COUNTY UNIT 3								
341 STRUCTURES AND IMPROVEMENTS	1,520,754	06-2051	80 - R2 *	(2)	1,520,754	2.64	-	549,749
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	339,065	06-2051	50 - R1.5 *	(3)	339,065	3.15	-	(672,273)
343 PRIME MOVERS - GENERAL	15,521,074	06-2051	50 - R1 *	(3)	15,521,074	3.23	-	(30,190,082)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	8,363,870	06-2051	9 - L0 *	35	8,363,870	8.48	-	(8,195,385)
344 GENERATORS	1,780,437	06-2051	60 - R2 *	(3)	1,780,437	2.76	-	242,502
345 ACCESSORY ELECTRIC EQUIPMENT	1,322,456	06-2051	50 - R2.5 *	(2)	1,322,456	2.74	-	404,082
346 MISCELLANEOUS POWER PLANT EQUIPMENT	165,828	06-2051	50 - S0.5 *	(2)	165,828	1.33	-	5,854,540
TOTAL WEST COUNTY UNIT 3	*29,013,484*				*29,013,484*	*3.76*	-	*(32,006,868)*
TOTAL WEST COUNTY COMBINED CYCLE PLANT	***94,897,402***				***94,897,402***	***4.47***	-	***(184,216,462)***

FLORIDA POWER AND LIGHT COMPANY

SUMMARY OF STIPULATED DEPRECIATION PARAMETERS, ANNUAL DEPRECIATION ACCRUALS, RATES AND THEORETICAL RESERVE IMBALANCES AS OF DECEMBER 31, 2016

	ANNUAL DEPRECIATION ACCRUALS FILED IN SECOND NOIA	STIPULATED PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	STIPULATED ANNUAL DEPRECIATION ACCRUALS	STIPULATED ANNUAL DEPRECIATION RATE	INCREASE/ (DECREASE)	THEORETICAL RESERVE IMBALANCE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(1)	(8)
CAPE CANAVERAL COMBINED CYCLE PLANT								
CAPE CANAVERAL COMBINED CYCLE								
341 STRUCTURES AND IMPROVEMENTS	2,211,721	06-2053	80 - R2 *	(2)	2,211,721	2.69	-	(644,283)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	1,416,280	06-2053	50 - R1.5 *	(3)	1,416,280	2.97	-	(516,734)
343 PRIME MOVERS - GENERAL	11,406,386	06-2053	50 - R1 *	(3)	11,406,386	2.96	-	5,899,811
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	14,298,917	06-2053	9 - L0 *	35	14,298,917	6.93	-	4,347,587
344 GENERATORS	1,974,222	06-2053	60 - R2 *	(3)	1,974,222	2.81	-	(1,112,147)
345 ACCESSORY ELECTRIC EQUIPMENT	3,141,522	06-2053	50 - R2.5 *	(2)	3,141,522	2.81	-	(1,624,829)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	306,960	06-2053	50 - S0.5 *	(2)	306,960	2.98	-	(257,518)
TOTAL CAPE CANAVERAL COMBINED CYCLE	*34,756,008*				*34,756,008*	*3.80*	-	*6,091,888*
TOTAL CAPE CANAVERAL COMBINED CYCLE PLANT	***34,756,008***				***34,756,008***	***3.80***	-	***6,091,888***
RIVIERA COMBINED CYCLE PLANT								
RIVIERA COMBINED CYCLE								
341 STRUCTURES AND IMPROVEMENTS	2,083,200	06-2054	80 - R2 *	(2)	2,083,200	2.58	-	1,982,431
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	6,213,983	06-2054	50 - R1.5 *	(3)	6,213,983	2.86	-	5,090,991
343 PRIME MOVERS - GENERAL	15,697,452	06-2054	50 - R1 *	(3)	15,697,452	2.99	-	4,209,739
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	9,822,967	06-2054	9 - L0 *	35	9,822,967	7.04	-	1,922,188
344 GENERATORS	2,187,632	06-2054	60 - R2 *	(3)	2,187,632	2.74	-	764,129
345 ACCESSORY ELECTRIC EQUIPMENT	2,249,473	06-2054	50 - R2.5 *	(2)	2,249,473	2.72	-	1,302,095
346 MISCELLANEOUS POWER PLANT EQUIPMENT	305,248	06-2054	50 - S0.5 *	(2)	305,248	2.67	-	870,458
TOTAL RIVIERA COMBINED CYCLE	*38,559,955*				*38,559,955*	*3.39*	-	*16,142,030*
TOTAL RIVIERA COMBINED CYCLE PLANT	***38,559,955***				***38,559,955***	***3.39***	-	***16,142,030***
PT EVERGLADES COMBINED CYCLE PLANT								
PT EVERGLADES COMBINED CYCLE								
341 STRUCTURES AND IMPROVEMENTS	2,678,119	06-2056	80 - R2 *	(2)	2,678,119	2.64	-	988,772
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	1,728,636	06-2056	50 - R1.5 *	(3)	1,728,636	2.90	-	582,817
343 PRIME MOVERS - GENERAL	14,955,771	06-2056	50 - R1 *	(3)	14,955,771	2.99	-	2,154,247
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	13,604,203	06-2056	9 - L0 *	35	13,604,203	7.11	-	1,864,243
344 GENERATORS	2,384,653	06-2056	60 - R2 *	(3)	2,384,653	2.73	-	841,083
345 ACCESSORY ELECTRIC EQUIPMENT	3,792,404	06-2056	50 - R2.5 *	(2)	3,792,404	2.74	-	1,299,400
346 MISCELLANEOUS POWER PLANT EQUIPMENT	367,552	06-2056	50 - S0.5 *	(2)	367,552	2.87	-	108,050
TOTAL PT EVERGLADES COMBINED CYCLE	*39,511,338*				*39,511,338*	*3.62*	-	*7,838,613*
TOTAL PT EVERGLADES COMBINED CYCLE PLANT	***39,511,338***				***39,511,338***	***3.62***	-	***7,838,613***
TOTAL COMBINED CYCLE PRODUCTION PLANT	**436,939,217**				**436,939,197**	***4.25***	-	**(295,947,938)**

FLORIDA POWER AND LIGHT COMPANY

SUMMARY OF STIPULATED DEPRECIATION PARAMETERS, ANNUAL DEPRECIATION ACCRUALS, RATES AND THEORETICAL RESERVE IMBALANCES AS OF DECEMBER 31, 2016

	ANNUAL DEPRECIATION ACCRUALS FILED IN SECOND NOIA	STIPULATED PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	STIPULATED ANNUAL DEPRECIATION ACCRUALS	STIPULATED ANNUAL DEPRECIATION RATE	INCREASE/ (DECREASE)	THEORETICAL RESERVE IMBALANCE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(1)	(8)
PEAKER PLANTS								
LAUDERDALE GTS								
341 STRUCTURES AND IMPROVEMENTS	25,126	06-2028	80 - R2 *	(2)	25,126	4.18	-	(52,022)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	9,191	06-2028	50 - R1.5 *	(3)	9,191	4.73	-	(21,304)
343 PRIME MOVERS - GENERAL	1,224,964	06-2028	50 - R1 *	(3)	1,224,964	8.25	-	(174,815)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	77,770	06-2028	25 - R1 *	29	77,770	4.18	-	(68,665)
344 GENERATORS	99,017	06-2028	60 - R2 *	(3)	99,017	5.66	-	(591,536)
345 ACCESSORY ELECTRIC EQUIPMENT	25,284	06-2028	50 - R2.5 *	(2)	25,284	6.02	-	(135,619)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	1,299	06-2028	50 - S0.5 *	(2)	1,299	6.21	-	(7,785)
TOTAL LAUDERDALE GTS	*1,462,651*				*1,462,651*	*7.43*	-	*(1,051,748)*
FT. MYERS GTS								
341 STRUCTURES AND IMPROVEMENTS	69,637	06-2028	80 - R2 *	(2)	69,637	7.40	-	(127,523)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	56,753	06-2028	50 - R1.5 *	(3)	56,753	7.84	-	(107,811)
343 PRIME MOVERS - GENERAL	840,243	06-2028	50 - R1 *	(3)	840,243	8.22	-	(150,972)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	117,550	06-2028	25 - R1 *	29	117,550	4.19	-	(156,932)
344 GENERATORS	371,695	06-2028	60 - R2 *	(3)	371,695	8.08	-	(924,076)
345 ACCESSORY ELECTRIC EQUIPMENT	267,985	06-2028	50 - R2.5 *	(2)	267,985	7.77	-	(366,448)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	1,682	06-2028	50 - S0.5 *	(2)	1,682	8.03	-	(4,526)
TOTAL FT. MYERS GTS	*1,725,545*				*1,725,545*	*7.58*	-	*(1,838,289)*
LAUDERDALE AND FT. MYERS PEAKERS								
341 STRUCTURES AND IMPROVEMENTS	1,178,784	06-2056	80 - R2 *	(2)	1,178,784	2.69	-	(471,424)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	773,331	06-2056	50 - R1.5 *	(3)	773,331	2.96	-	(290,552)
343 PRIME MOVERS - GENERAL	6,497,296	06-2056	50 - R1 *	(3)	6,497,296	3.04	-	(2,244,319)
343.2 PRIME MOVERS - CAPITAL SPARE PARTS	2,443,098	06-2056	25 - R1 *	29	2,443,098	2.91	-	(760,487)
344 GENERATORS	1,066,810	06-2056	60 - R2 *	(3)	1,066,810	2.79	-	(429,403)
345 ACCESSORY ELECTRIC EQUIPMENT	1,696,934	06-2056	50 - R2.5 *	(2)	1,696,934	2.80	-	(697,752)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	164,463	06-2056	50 - S0.5 *	(2)	164,463	2.93	-	(69,730)
TOTAL LAUDERDALE AND FT. MYERS PEAKERS	*13,820,716*				*13,820,716*	*2.93*	-	*(4,963,667)*
TOTAL PEAKER PLANTS	**17,008,912**				**17,008,912**	***3.30***	**-**	**(7,853,703)**

FLORIDA POWER AND LIGHT COMPANY

SUMMARY OF STIPULATED DEPRECIATION PARAMETERS, ANNUAL DEPRECIATION ACCRUALS, RATES AND THEORETICAL RESERVE IMBALANCES AS OF DECEMBER 31, 2016

	ANNUAL DEPRECIATION ACCRUALS FILED IN SECOND NOIA	STIPULATED PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE	STIPULATED ANNUAL DEPRECIATION ACCRUALS	STIPULATED ANNUAL DEPRECIATION RATE	INCREASE/ (DECREASE)	THEORETICAL RESERVE IMBALANCE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(1)	(8)
SOLAR PRODUCTION PLANT								
DESOTO SOLAR								
341 STRUCTURES AND IMPROVEMENTS	161,864	06-2039	SQUARE *	0	161,864	3.49	-	(93,392)
343 PRIME MOVERS - GENERAL	3,991,517	06-2039	SQUARE *	0	3,991,517	3.36	-	(181,250)
345 ACCESSORY ELECTRIC EQUIPMENT	1,005,979	06-2039	SQUARE *	0	1,005,979	3.65	-	(1,793,915)
TOTAL DESOTO SOLAR	*5,159,360*				*5,159,360*	*3.42*	-	*(2,068,557)*
SPACE COAST SOLAR								
341 STRUCTURES AND IMPROVEMENTS	137,690	06-2040	SQUARE *	0	137,690	3.45	-	(98,507)
343 PRIME MOVERS - GENERAL	1,744,523	06-2040	SQUARE *	0	1,744,523	3.30	-	597,781
345 ACCESSORY ELECTRIC EQUIPMENT	220,650	06-2040	SQUARE *	0	220,650	3.51	-	(242,695)
TOTAL SPACE COAST SOLAR	*2,102,863*				*2,102,863*	*3.33*	-	*256,579*
MARTIN SOLAR								
341 STRUCTURES AND IMPROVEMENTS	637,205	06-2045	SQUARE *	0	637,205	2.99	-	(589,985)
343 PRIME MOVERS - GENERAL	11,684,485	06-2045	SQUARE *	0	11,684,485	2.88	-	1,380,595
345 ACCESSORY ELECTRIC EQUIPMENT	126,641	06-2045	SQUARE *		126,641	2.99	-	(131,884)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	38	06-2045	SQUARE *	0	38	2.85	-	15
TOTAL MARTIN SOLAR	*12,448,369*				*12,448,369*	*2.89*	-	*658,741*
BABCOCK RANCH SOLAR								
341 STRUCTURES AND IMPROVEMENTS	137,491	06-2046	SQUARE *	0	137,491	3.37	-	(49,897)
343 PRIME MOVERS - GENERAL	3,510,209	06-2046	SQUARE *	0	3,510,209	3.37	-	(1,273,912)
345 ACCESSORY ELECTRIC EQUIPMENT	816,689	06-2046	SQUARE *	0	816,689	3.37	-	(296,390)
TOTAL BABCOCK RANCH SOLAR	*4,464,389*				*4,464,389*	*3.37*	-	*(1,620,199)*
MANATEE SOLAR								
341 STRUCTURES AND IMPROVEMENTS	139,230	06-2046	SQUARE *	0	139,230	3.38	-	(61,435)
343 PRIME MOVERS - GENERAL	3,557,049	06-2046	SQUARE *	0	3,557,049	3.38	-	(1,569,551)
345 ACCESSORY ELECTRIC EQUIPMENT	827,019	06-2046	SQUARE *	0	827,019	3.38	-	(364,923)
TOTAL MANATEE SOLAR	*4,523,298*				*4,523,298*	*3.38*	-	*(1,995,909)*
CITRUS SOLAR								
341 STRUCTURES AND IMPROVEMENTS	141,843	06-2046	SQUARE *	0	141,843	3.37	-	(51,575)
343 PRIME MOVERS - GENERAL	3,615,886	06-2046	SQUARE *	0	3,615,886	3.37	-	(1,314,759)
345 ACCESSORY ELECTRIC EQUIPMENT	842,541	06-2046	SQUARE *		842,541	3.37	-	(306,353)
TOTAL CITRUS SOLAR	*4,600,270*				*4,600,270*	*3.37*	-	*(1,672,687)*
TOTAL SOLAR PRODUCTION PLANT	**33,298,549**				**33,298,549**	***3.18***	**-**	**(6,442,031)**
TOTAL PRODUCTION PLANT	**913,519,775**				**899,049,977**	***3.94***	**(14,469,754)**	**(421,593,879)**

FLORIDA POWER AND LIGHT COMPANY

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		(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(1)	(8)
TRANSMISSION, DISTRIBUTION, AND GENERAL PLANT									
	TRANSMISSION PLANT								
350.2	EASEMENTS	3,013,708		100 - R4	0	2,050,771	0.85	(962,937)	27,710,304
352	STRUCTURES AND IMPROVEMENTS	2,626,625		65 - R3	(15)	2,626,625	1.70	-	5,942,613
353	STATION EQUIPMENT	41,155,580		44 - L1	0	35,542,525	2.04	(5,613,055)	138,752,531
353.1	STATION EQUIPMENT - STEP-UP TRANSFORMERS	14,050,185		38 - R1	0	10,546,543	2.64	(3,503,642)	(707,602)
354	TOWERS AND FIXTURES	5,877,891		70 - R4	(15)	3,857,806	1.11	(2,020,085)	85,884,836
355	POLES AND FIXTURES	36,188,883		55 - S0	(40)	28,779,164	2.32	(7,409,719)	132,265,780
356	OVERHEAD CONDUCTORS AND DEVICES	24,232,975		55 - S0	(45)	20,331,334	2.38	(3,901,641)	95,103,892
357	UNDERGROUND CONDUIT	1,081,448		65 - R4	0	1,081,448	1.43	-	3,688,311
358	UNDERGROUND CONDUCTORS AND DEVICES	1,952,829		65 - R3	(20)	1,952,829	1.87	-	(1,000,451)
359	ROADS AND TRAILS	1,509,809		75 - R4	(10)	1,509,809	1.33	-	8,210,118
	TOTAL TRANSMISSION PLANT	**131,689,933**				**108,278,854**	***2.05***	**(23,411,079)**	**495,850,333**
	DISTRIBUTION PLANT								
361	STRUCTURES AND IMPROVEMENTS	3,468,842		65 - R3	(15)	3,468,842	1.75	-	2,356,090
362	STATION EQUIPMENT	41,067,728		51 - S0.5	(5)	33,130,887	1.90	(7,936,841)	104,861,493
364.1	POLES, TOWERS AND FIXTURES - WOOD	58,351,587		44 - R2.5	(60)	38,803,869	3.58	(19,547,718)	18,049,373
364.2	POLES, TOWERS AND FIXTURES - CONCRETE	28,813,668		56 - S0	(60)	20,177,832	2.85	(8,635,836)	3,471,154
365	OVERHEAD CONDUCTORS AND DEVICES	73,133,316		57 - R1	(60)	51,150,477	2.57	(21,982,839)	221,001,031
366.6	UNDERGROUND CONDUIT - DUCT SYSTEM	21,675,264		70 - R3	0	21,675,264	1.42	-	10,230,998
366.7	UNDERGROUND CONDUIT - DIRECT BURIED	3,880,685		50 - R4	0	3,880,685	2.00	-	(126,918)
367.6	UNDERGROUND CONDUCTORS AND DEVICES - DUCT SYSTEM	41,878,881		46 - L0.5	0	33,724,737	1.96	(8,154,144)	136,402,874
367.7	UNDERGROUND CONDUCTORS AND DEVICES - DIRECT BURIED	19,235,979		45 - L1	0	12,710,077	1.74	(6,525,902)	123,342,486
368	LINE TRANSFORMERS	64,778,557		34 - S0	(15)	64,778,557	2.98	-	203,438,869
369.1	SERVICES - OVERHEAD	18,428,378		56 - R1.5	(85)	14,004,670	3.26	(4,423,708)	10,329,203
369.6	SERVICES - UNDERGROUND	19,674,557		45 - R2	(15)	19,674,557	2.40	-	38,427,583
370	METERS	3,095,847		38 - R2	(20)	2,568,796	2.84	(527,051)	4,963,443
370.1	METERS - AMI	50,162,753		20 - R2.5	(20)	45,341,877	6.03	(4,820,876)	(3,367,864)
371	INSTALLATIONS ON CUSTOMER'S PREMISES	2,591,609		30 - L0	(15)	2,591,609	3.33	-	8,612,283
373	STREET LIGHTING AND SIGNAL SYSTEMS	13,075,070		39 - L0	(15)	11,431,801	2.47	(1,643,269)	69,097,230
	TOTAL DISTRIBUTION PLANT	**463,312,721**				**379,114,537**	***2.58***	**(84,198,184)**	**951,089,330**
	GENERAL PLANT								
390	STRUCTURES AND IMPROVEMENTS	8,650,821		55 - R1.5	10	6,533,465	1.50	(2,117,356)	24,486,077
392.1	AUTOMOBILES	1,420,982		6 - L2.5	15	1,420,982	15.72	-	(566,443)
392.2	LIGHT TRUCKS	4,748,098		9 - L3	15	4,748,098	10.00	-	(1,522,132)
392.3	HEAVY TRUCKS	14,874,545		13 - S3	15	13,248,810	5.48	(1,625,735)	20,207,137
392.4	TRACTOR TRAILERS	20,213		9 - L2.5	5	20,213	2.63	-	249,659
392.9	TRAILERS	1,050,223		20 - L1	15	1,050,223	4.99	-	(2,237,075)
396.1	POWER OPERATED EQUIPMENT	336,070		11 - L1.5	15	336,070	7.05	-	192,165
397.8	COMMUNICATION EQUIPMENT - FIBER OPTICS	233,429		20 - S2	0	233,429	1.95	-	4,032,969
	TOTAL GENERAL PLANT	**31,334,381**				**27,591,290**	***3.57***	**(3,743,091)**	**44,842,357**
TOTAL TRANSMISSION, DISTRIBUTION AND GENERAL PLANT		**626,337,035**				**514,984,681**	***2.48***	**(111,352,354)**	**1,491,782,020**
GRAND TOTAL		**1,539,856,809**				**1,414,034,653**	***3.25***	**(125,822,108)**	**1,070,188,133**

* CURVE SHOWN IS INTERIM SURVIVOR CURVE. LIFE SPAN METHOD IS USED.

110

Joint Stipulation and Agreement for Interim Resolution of Hedging Issues, filed on October 24, 2016 in Docket No. 160001-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 110
PARTY: STAFF – (DIRECT)
DESCRIPTION: Joseph McCallister, H.R. Ball, Penelope Rusk

FILED OCT 24, 2016
DOCUMENT NO. 08429-16
FPSC - COMMISSION CLERK

DUKE ENERGY FLORIDA

Matthew R. Bernier
Senior Counsel
Duke Energy Florida, LLC.

October 24, 2016

VIA ELECTRONIC FILING

Ms. Carlotta Stauffer, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: *Fuel and purchased power cost recovery clause with generating performance incentive factor; Docket No. 160001-EI*

Dear Ms. Stauffer:

Please find enclosed for electronic filing a Joint Stipulation and Agreement for Interim Resolution of Hedging Issues of Duke Energy Florida ("DEF"), Gulf Power Company ("Gulf"), Tampa Electric Company ("TECO"), the Office of Public Counsel ("OPC"), the Florida Industrial Power Users Group ("FIPUG") and the Florida Retail Federation ("FRF") for the above referenced docket.

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

Respectfully,

s/Matthew R. Bernier

Matthew R. Bernier
Senior Counsel
Matthew.Bernier@duke-energy.com

MRB/mw
Enclosures

Duke Energy Florida, LLC
Docket No.: 160001
CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail this 24th day of October, 2016 to all parties of record as indicated below.

s/Matthew R. Bernier

Attorney

Danijela Janjic Suzanne Brownless Office of General Counsel Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 sbrownle@psc.state.fl.us djanjic@psc.state.fl.us asoete@psc.state.fl.us James D. Beasley J. Jeffry Wahlen Ashley M. Daniels Ausley McMullen Law Firm P.O. Box 391 Tallahassee, FL 32302 jbeasley@ausley.com jwahlen@ausley.com adaniels@ausley.com Jeffrey A. Stone Russell A. Badders Steven R. Griffin Beggs & Lane P.O. Box 12950 Pensacola, FL 32591 jas@beggslane.com rab@beggslane.com srg@beggslane.com James W. Brew Laura A. Wynn Stone Matheis Xenopoulos & Brew 1025 Thomas Jefferson Street NW 8th Floor, West Tower Washington, DC 20007 jbrew@smxblaw.com law@smxblaw.com	Mike Cassel, Director Regulatory Affairs Florida Public Utilities Company 1750 S 14th Street, Suite 200 Fernandina Beach, FL 32034 mcassel@fpuc.com Robert L. McGee, Jr. Gulf Power Company One Energy Place Pensacola, FL 32520-0780 rlmcgee@southernco.com Beth Keating Gunster, Yoakley & Stewart, P.A. 215 South Monroe Street, Suite 601 Tallahassee, FL 32301 bkeating@gunster.com Charles J. Rehwinkel / Erik Sayler J.R. Kelly / Patty Christensen Tarik Noriega Office of Public Counsel c/o The Florida Legislature 111 W. Madison Street, Room 812 Tallahassee, FL 32399-1400 rehwinkel.charles@leg.state.fl.us sayler.erik@leg.state.fl.us kelly.jr@leg.state.fl.us 2hristensen.patty@leg.state.fl.us noriega.tarik@leg.state.fl.us Robert Scheffel Wright John T. LaVia, III c/o Gardner Law Firm 1300 Thomaswood Drive Tallahassee, FL 32308 schef@gbwlegal.com jlavia@gbwlegal.com	Ms. Paula K. Brown Manager, Regulatory Coordination Tampa Electric Company P.O. Box 111 Tampa, FL 33601 regdept@tecoenergy.com John Butler Maria Moncada Florida Power & Light Company 700 Universe Boulevard (LAW/JB) Juno Beach, FL 33408-0420 john.butler@fpl.com maria.moncada@fpl.com Kenneth Hoffman Florida Power & Light Company 215 S. Monroe Street, Suite 810 Tallahassee, FL 32301-1858 ken.hoffman@fpl.com Jon C. Moyle, Jr. Moyle Law Firm, P.A. 118 North Gadsden Street Tallahassee, FL 32301 jmoyle@moylelaw.com Raoul G. Cantero, III White & Case, LLP Southeast Financial Center, Suite 4900 200 South Biscayne Boulevard Miami, FL 33131-2352 rcantero@whitecase.com

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause And Generating Performance Incentive Factor.	)))))	DOCKET NO. 160001-EI FILED: October 24, 2016

JOINT STIPULATION AND AGREEMENT FOR INTERIM RESOLUTION OF HEDGING ISSUES

Electric investor-owned utilities Duke Energy Florida ("DEF"), Gulf Power Company ("Gulf") and Tampa Electric Company ("TECO") (collectively the IOUs), the Office of Public Counsel ("OPC"), the Florida Industrial Power Users Group ("FIPUG") and the Florida Retail Federation ("FRF"), all of the foregoing collectively referred to as the Parties, hereby jointly enter into this Stipulation and Agreement ("Agreement"), all of which is subject to review by the Florida Public Service Commission ("Commission").

W I T N E S S E T H:

WHEREAS, financial hedging of natural gas prices by the IOUs has been a subject of review in light of hedging costs in recent years; and

WHEREAS, issues regarding whether modifications to or cessation of existing Commission approved hedging practices are currently pending in the 2016 Fuel and Purchased Power Cost Recovery Docket, with the hearing in that Docket scheduled to be commenced on November 2, 2016; and

WHEREAS, Staff witnesses Gettings and Cicchetti filed testimony in this proceeding on September 23, 2016, on behalf of the Commission's Staff proposing a new risk responsive hedging model; and

WHEREAS, the IOUs had only approximately one week to analyze and respond to the risk responsive proposal; and

WHEREAS, witness Lawton filed testimony on behalf of OPC in this proceeding on September 23, 2016, advocating the cessation of financial hedging of natural gas unless circumstances change substantially; and

WHEREAS, all Parties wish to resolve all concerns regarding hedging on a going-forward basis, in a manner that works in the best interests of all of the customers of the IOUs; and

WHEREAS, a careful analysis of all identified and potential risk management approaches, including whether financial hedging of natural gas should continue, would benefit all stakeholders and allow the Commission to resolve hedging issues in the manner most beneficial to electric consumers in Florida; and

WHEREAS, the ultimate resolution of the pending hedging issues may involve a range of alternatives, including but not limited to the Gettings/Cicchetti approach, a reduction in the current levels of hedging and hedging durations, use of different financial products, or the termination of financial hedging altogether. All Parties to this stipulation believe that a careful consideration of the various alternatives will produce a result that is in the best interests of electric customers in the State.

NOW, THEREFORE, in consideration of the foregoing, the Parties stipulate and agree as follows:

1. The IOUs will put in place a 100 percent moratorium on any new hedges effective immediately upon the Commission's approval of this Agreement, with that moratorium extending through calendar year 2017, subject to the provisions of paragraph

5. The moratorium will not affect any financial hedges for natural gas executed prior to the effective date of the moratorium under the IOUs' 2016 risk management plans or prior plans.

2. The IOUs will withdraw their proposed 2017 Risk Management Plans.

3. No hedges executed by the Florida IOUs prior to the effective date of the moratorium will be impacted by the proposed moratorium.

4. The Parties will cooperate with each other and with the Commission's Staff to engage in a workshop or workshops, as soon as practicable, to consider all alternatives to prospectively resolving the hedging issues including but not limited to the Gettings/Cicchetti approach, a reduction in the current levels of hedging and hedging durations, use of different financial products, or the termination of financial hedging altogether, with the goal of either establishing a basis for the IOUs to present Risk Management Plans for 2018 that all stakeholders can agree upon or not object to or reaching some other mutually agreeable resolution of the hedging issues currently identified in Docket No. 160001-EI.

5. The Parties will negotiate in good faith to reach a settlement or other basis for the disposition of the hedging issues in time to present that anticipated resolution to the Commission concurrent with or prior to submittal of the IOUs' 2018 Risk Management Plans on or about August 1, 2017, or as directed by the Order Establishing Procedure in Docket No. 170001-EI ("2017 OEP"). If the parties fail to reach a settlement as discussed herein, the IOUs may submit proposed 2018 Risk Management Plans as directed by the 2017 OEP for consideration at the November 2017 hearing, in advance of the expiration of the one year moratorium at the end of calendar year 2017,

and the other Parties are free to advocate whatever positions they believe appropriate with respect to any such 2018 Plans.

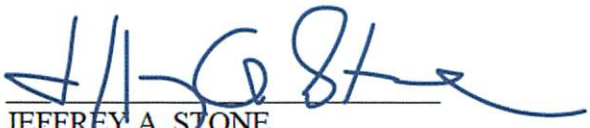
6. The provisions of this Agreement are contingent on Commission approval of revised and substituted positions as a stipulation on the hedging issues in Docket No. 160001-EI consistent with the terms of this Agreement . The Parties agree that approval of this Agreement is in the public interest. The Parties further agree that they will support this Agreement and will not request or support any order, relief, outcome or result in conflict with the terms hereof in any administrative or judicial proceeding relating to, reviewing, or challenging the establishment, approval, adoption, or implementation of the Agreement or the subject matter hereof. No party will assert in any proceeding before the Commission or any court that this Agreement or any of the terms in the Agreement shall have any precedential value, except to enforce the provisions of the Agreement.

7. This Agreement is dated as of October 24, 2016. It may be executed in counterpart originals, and a scanned .pdf copy of an original signature shall be deemed an original. Any person or entity that executes a signature page to this Agreement shall become and be deemed a party with the full range of rights and responsibilities provided hereunder, notwithstanding that such person or entity is not listed in the first recital above and executes the signature page subsequent to the date of this Agreement, it being expressly understood that the addition of any such additional party(ies) shall not disturb or diminish the benefits of this Agreement to any current party.

IN WITNESS WHEREOF, the Parties evidence their acceptance and agreement with the provisions of this Agreement by their signature.

MATTHEW R. BERNIER
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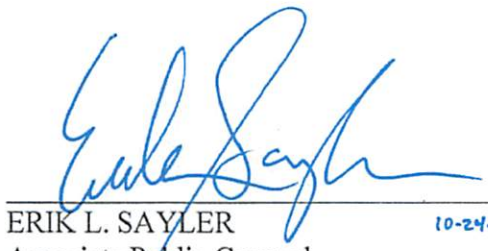


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111

FPL's Adoption of Hedging Stipulation, filed on October 24, 2016 in Docket No. 160001-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 111
PARTY: STAFF – (DIRECT)
DESCRIPTION: Gerard J. Yupp

FILED OCT 24, 2016
DOCUMENT NO. 08438-16
FPSC - COMMISSION CLERK



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October 24, 2016

- VIA ELECTRONIC FILING -

Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket No. 160001-EI

Dear Ms. Stauffer:

This is to advise the Commission and the parties to the above-referenced docket that Florida Power & Light Company ("FPL") supports the Joint Stipulation and Agreement for Interim Resolution of Hedging Issues that was filed in said docket on October 24, 2016 (the "Joint Stipulation"). FPL adopts and agrees to be bound by the terms of the Joint Stipulation; provided, however, that if the Commission approves the Stipulation and Settlement that FPL entered into with the Office of Public Counsel, the South Florida Hospital and Healthcare Association and the Florida Retail Federation on October 6, 2016 in Docket No. 160021-EI and consolidated dockets (the "Proposed Settlement Agreement"), then the provisions of Paragraph 16 in the Proposed Settlement Agreement concerning hedging will control with respect to FPL over any contrary provisions of the Joint Stipulation.

If you should have any questions, please do not hesitate to contact me.

Sincerely,

/s/ John T. Butler
John T. Butler

cc: Parties of record

CERTIFICATE OF SERVICE
Docket No. 160001-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic service on this 24th day of October, 2016 to the following:

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By: */s/ John T. Butler*
John T. Butler
Fla. Bar No. 283479

3651106

112

DEF's Response to PCS First Set of Interrogatories, No. 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 112
PARTY: STAFF – (DIRECT)
DESCRIPTION: Christopher A. Menendez

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor	Docket No. 160001-EI Dated: October 6, 2016

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO PCS' FIRST SET OF INTERROGATORIES (NO. 1)

Duke Energy Florida, LLC ("DEF") responds to White Springs Agricultural Chemicals, Inc., d/b/a PCS Phosphate's ("PCS") First Set of Interrogatories (No. 1) as follows:

INTERROGATORIES

1. For this question, please refer to the attached Excel sheet (Attachment PCS-A), which includes information and calculations based on information from DEF witnesses in several prior fuel dockets (Dockets No. 160001-EI, 150001-EI, 140001-EI, 130001-EI, and 120001-EI):

   a. Please confirm that the information in each of the tables included in Attachment PCS-A accurately reflects the data filed by DEF in the indicated past fuel dockets (see above).

   Response:

   The excerpts, as provided in Attachment PCS-A, accurately reflect the data filed by DEF in the indicated past fuel dockets. DEF did identify immaterial rounding variances of $1-$2 or 1-2 MWhs on certain totals. Given the immateriality of the rounding variances, DEF does not believe they impact the overall accuracy of Attachment PCS-A and as such, they are not listed in DEF's response to question 1b.

160001 Hearing Exhibits 00499

b. If any of the entries are not consistent with the indicated filings, please identify the cell which is incorrect and please provide the correct figure, including an explanation of how that figure was calculated.

Response:

Please see DEF's Response to Interrogatory No. 1a.

160001 Hearing Exhibits 00500

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF PINELLAS

I hereby certify that on this 4 day of October, 2016, 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 he acknowledged before me that he provided the answers to interrogatory number 1 from PCS PHOSPHATE'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NO. 1) in Docket No. 160001-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 4th day of October, 2016.

Christopher Menendez

MONIQUE WEST
MY COMMISSION # FF 244727
EXPIRES: June 28, 2019
Bonded Thru Notary Public Underwriters

Notary Public
State of Florida

My Commission Expires: 6/28/19

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DEF's Response to OPC's Second Set of Interrogatories, Nos. 11, 12-13 (Redacted), 14, 15, 16 (Redacted), 17, 18

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 113
PARTY: STAFF – (DIRECT)
DESCRIPTION: Joseph McCallister

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor	Docket No. 160001-EI Dated: August 22, 2016

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO CITIZENS' SECOND SET OF INTERROGATORIES (NOS. 11-18)

Duke Energy Florida, LLC ("DEF"), responds to the Citizens of the State of Florida, through the Office of the Public Counsel's ("Citizens" or "OPC") Second Set of Interrogatories to DEF (Nos. 11-18) as follows:

INTERROGATORIES

11. Natural gas financial hedging gain or loss for 2016 as of July 31, 2016:

a. Please update the projected amount of the anticipated natural gas financial hedging loss that was provided in the Company's May 2016 response to OPC Interrogatory No. 2.

Answer:

For natural gas, DEF is currently estimating a net hedge cost for calendar year 2016 of approximately $145.5 million based on July 29, 2016 closing market prices. The date of July 29, 2016 is being used to estimate as it is the last business day of the month that prices were published and July 31, 2016 is a Sunday.

b. What was the actual natural gas financial hedging loss from January 1 through July 31, 2016?

Answer:

160001 Hearing Exhibits 00503

For natural gas, DEF net hedge cost from January 1 through July 31, 2016 was approximately $114.9 million.

c. What is the estimated amount of natural gas financial hedging gain or loss from August 1 through December 31, 2016?

Answer:

For natural gas, DEF is currently estimating a net hedge cost for August 1 through December 31, 2016 of approximately $30.6 million based on July 29, 2016 closing market prices. The date of July 29, 2016 is being used to estimate as it is the last business day of the month that prices were published as July 31, 2016 is a Sunday.

d. Since the Company's May 2016 response to OPC on the projected 2016 natural gas financial hedging loss, please explain whether the 2016 projected loss has increased or decreased and by how much in terms of dollars and percentages.

Answer:

The projected 2016 natural gas financial hedge cost has decreased from the May 2016 response to OPC. DEF is currently estimating the projected 2016 natural gas financial hedging cost to decrease by approximately $29.2 million or approximately 17% from the May 2016 projection based on actual hedge cost for January 2016 through July 2016, and estimated net hedge costs for the months of August 2016 through December 2016 based on July 29, 2016 closing market price. The date of July 29, 2016 is being used to estimate as it is the last business day of the month that prices were published and July 31, 2016 is a Sunday.

12. Projected natural gas financial hedging gains or losses for 2017 as of July 31, 2016:

a. Please provide the projected natural gas hedging gain or loss for calendar year 2017 based on the hedging positions the Company has already executed.

Answer:

The estimated natural gas hedge cost for calendar year 2017 based on market prices as of July 29, 2016 is approximately $25.8 million. The date of July 29, 2016 is being used to estimate as it is the last business day of the month that prices were published and July 31, 2016 is a Sunday.

REDACTED

b. As part of this response, what percentage of the total anticipated natural gas burn for 2017 has already been hedged?

Answer:

As of July 29, 2016, DEF has hedged approximately [redacted] percent of its forecasted natural gas burns for calendar year 2017. The date of July 29, 2016 is being used to estimate as it is the last business day of the month that prices were published versus July 31, 2016 which is a Sunday.

13. Projected natural gas financial hedging gains or losses for 2018 as of July 31, 2016:

a. Please provide the projected natural gas hedging gain or loss for calendar year 2018 based on the hedging positions the Company has already executed.

Answer:

The estimated natural gas hedge gain for calendar year 2018 as of July 29, 2016 is approximately $3.7 million. The date of July 29, 2016 is being used to estimate as it is the last business day of the month that prices were published and July 31, 2016 is a Sunday.

REDACTED

b. As part of this response, what percentage of the total anticipated natural gas burn for 2018 has already been hedged?

Answer:

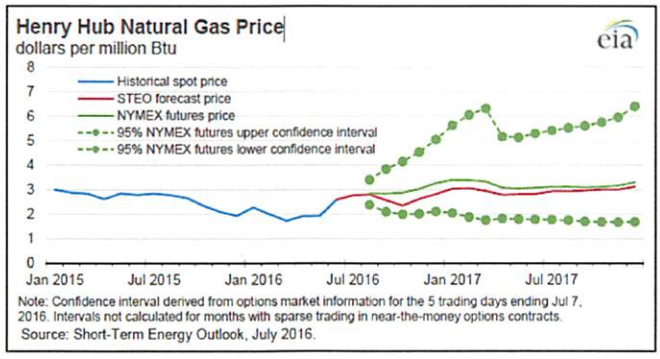
As of July 29, 2016, DEF has hedged approximately [redacted] percent of its forecasted natural gas burns for calendar year 2018. The date of July 29, 2016 is being used to estimate as it is the last business day of the month that prices were published and July 31, 2016 is a Sunday.

14. Please describe all the benefits customers receive from natural gas financial hedging.

Answer:

The benefits of locking in prices via a structured hedging over time are to reduce price risk and volatility, and provide greater fuel cost certainty for DEF's customers. The benefits of hedging are important given DEF's overall fuel mix. Natural gas represents approximately 65% of DEF's owned and tolled generation output based on the summer 2016 forecast. If only DEF-owned generation was considered, natural gas is estimated at 72% of the total fuel mix for 2017.

In addition, future prices are uncertain and neither DEF nor any forecaster can predict where actual prices and volatility will be in the future. With respect to quantifying the potential statistical range of natural gas prices within a 95% confidence interval of natural gas prices for 2017, DEF is providing information from the US Energy Information Administration (EIA) July 2016 Short-Term Energy and Summer Fuels Outlook. EIA is forecasting Henry Hub spot prices to average $2.95/MMBtu in 2017 with a lower and upper limit with a 95% confidence interval of $1.79/MMBtu and $5.69/MMBtu.



In addition to the above statistical ranges, as outlined below forward NYMEX natural gas prices for the periods of 2017 through 2019, reached historical low price levels during the first quarter of 2016 but have trended higher over the last few months.



Given this, DEF believes continuing to hedge a portion provides customer benefits by ensuring a consistent execution approach over a multi-year period to manage fuel cost risk given the number of factors that can ultimately impact prices and trends and ensures a degree of cost volatility risk mitigation from one fuel period to another.

15. Please describe all the benefits, including cash flow and working capital benefits, the Company receives from natural gas financial hedging.

Answer:

This Commission has found that customers benefit from stable rates that allow the customer to budget for electric bills and that hedging has contributed to the stability of fuel factors (*see* Order No. PSC-08-0667-PAA-EI, p. 11). Hedging benefits the Company by providing the needed risk management tools to prudently manage fuel cost exposure and reduce the risk of fuel cost fluctuations for a portion of its projected fuel usage.

16. As of the June 9, 2016 Agenda Conference, what months were already fully hedged for 2017 (i.e., where the hedging procurement for those months was fully completed) pursuant to the unmodified 2016 Risk Management Plan?

Answer:

DEF's targeted hedging percentage ranges outlined in its Risk Management Plan are based on calendar year forecasted burns (January through December). The volumes hedged over time are based on periodic updated fuel forecasts and the actual hedge percentages for any month, rolling period, or calendar annual period may come in higher or lower than the target minimum hedge percentages and hedging ranges because of changing forecasts, and actual fuel burns versus forecasted fuel burns. In its Risk Management Plan, DEF outlined the targeted hedge percentages ranges are based on forecasted burns are for calendar year periods. The actual hedge percentages may differ from hedge percentages based on forecasts.

Outlined below were the total burn forecasts, hedge volumes, and hedging percentages for each month and in total for 2017:

Month	Natural Gas Forecast (MMBtu)	Hedge Volume (MMBtu)	Percent Hedge
January-17	[redacted]		
February-17			
March-17			
April-17			
May-17			
June-17			
July-17			
August-17			
September-17			
October-17			
November-17			
December-17			

17. As of the June 9, 2016 Agenda Conference and pursuant to the unmodified 2016 Risk Management Plan:

a. What months remained unhedged for 2017 (i.e., where the hedging procurement for those months was not fully executed)?

Answer:

Please see DEF's response to Interrogatory number 16.

b. How much volume of natural gas was hedged?

Answer:

Please see DEF's response to Interrogatory number 16.

c. How much volume of natural gas remained to be hedged?

Answer:

Please see DEF's response to Interrogatory number 16.

18. Does the Company intend to make any additional modifications its Risk Management Plan, if so, please explain?

Answer:

DEF's proposed Modifications are outlined in the 2017 Risk Management Plan filed on August 4, 2016. DEF will make other modifications as instructed by the FPSC.

AFFIDAVIT

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

I hereby certify that on this 15 day of August, 2016, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared JOSEPH MCCALLISTER, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 11, 12, 13, 14, 15, 16, 17, and 18, from CITIZENS SECOND SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NOS. 11-18) in Docket No. 160001-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 15 day of August, 2016.

KATIE JAMIESON
Notary Public, North Carolina
Gaston County
My Commission Expires

JOSEPH MCCALLISTER

Katie Jamieson
Notary Public
State of North Carolina

My Commission Expires:

June 14, 2021

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DEF's Responses to OPC's Second Set of Interrogatories, Nos. 12-13, 16 (Confidential DN 06926-16)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 114
PARTY: STAFF – (DIRECT)
DESCRIPTION: Joseph McCallister

EXHIBIT NO. 115

DOCKET NO: 160001-EI

WITNESS: Christopher A. Menendez

PARTY: PCS

DESCRIPTION:

DOCUMENTS: PCS Phosphate's First Set of Interrogatories to DEF, No. 1, including excel file "Attachment PCS-A.xlsx."

PROFFERED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 160001-EI EXHIBIT: 115
PARTY: PCS
DESCRIPTION: First IRROGS to DEF No.1

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 160001-EI DATED: SEPTEMBER 16, 2016

PCS PHOSPHATE'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NO. 1)

White Springs Agricultural Chemicals d/b/a PCS Phosphate, by and through its undersigned attorney, propounds the following interrogatories, pursuant to Rule 1.340, Florida Rules of Civil Procedure, to Duke Energy Florida, LLC (DEF). These interrogatories shall be answered under oath by you or your agent, who is qualified and who will be identified, with the answers being served as provided by the Rules of Civil Procedure, **and within the time period set out in Order No. PSC-16-0109-PCO-EI.** As provided by Rule 1.340(a), Florida Rules of Civil Procedure, each interrogatory shall be answered separately and fully in writing under oath unless it is objected to. Each answer shall be signed by the person making it.

Give the name, address, and relationship to DEF of those persons providing the answers to each of the following interrogatories.

If an interrogatory contained herein asks for information that has already been provided or is in the process of being provided to the Commission through a Commission audit, please so state, indicating the date provided and the audit document/record request number.

DEFINITIONS

"You", "your", "Company", or "DEF" refers to Duke Energy Florida, LLC, its employees and authorized agents.

"Document" refers to written matter of any kind, regardless of its form, and to information recorded on any storage medium, whether in electrical, optical or electromagnetic form, and capable of reduction to writing by the use of computer hardware and software.

"Identify" means:

(a) With respect to a person, to state the person's name, address and business relationship (e.g., "employee") to the Company;

(b) With respect to a document, to state the nature of the document in sufficient detail for identification in a request for production, its date, its author, and to identify its custodian. If the information or document identified is recorded in electrical, optical or electromagnetic form, identification includes a description of the computer hardware or software required to reduce it to readable form.

INSTRUCTIONS

1. To the extent an interrogatory calls for information which cannot now be precisely and completely furnished, such information as can be furnished should be included in the answer, together with a statement that further information cannot be furnished, and a statement as to the reasons therefore. If you expect to obtain further information between the time answers are served and the time of hearing, you are requested to state this fact in each answer. If the information which cannot now be furnished is believed to be available to another person, identify such other person and the reasons for believing such person has the described information.

2. In the event any interrogatory herein calls for information or for the identification of a document which you deem to be privileged, in whole or in part, the information should be given or the document identified to the fullest extent possible consistent with such claim of privilege and specify the grounds relied upon for the claim of privilege.

3. Documents or reports to be identified shall include all documents in your possession, custody and control and all other documents of which you have knowledge. If a document is produced in response to an interrogatory, please produce a scanned copy of the originals and all versions that are different in any way from the original, whether by interlineation, receipt stamp or notation. If the Utility does not have possession, custody, or control of the originals of the documents requested, please produce a scanned copy of the version(s) in the possession, custody, or control of the Utility, however, made.

4. Separate answers shall be furnished for each interrogatory, although where the context permits, an interrogatory may be answered by reference to the answer furnished to another interrogatory.

5. For each interrogatory, identify the name, address, telephone number and position of the person responsible for providing the answer.

6. Please provide all responses to these interrogatories that include workpapers, data, calculations and spreadsheets in non-password protected and executable PC-compatible computer program/models/software. Formulae, links, and cells, formatting, metadata and any other original features assisting in calculation should be intact. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

7. To the extent practicable, OPC requests that responsive documents which cannot be provided in original electronic format be provided on compact disk(s) or other agreed upon electronic medium in an OCR (Optical Character Recognition) searchable PDF format with bate stamp numbering. OPC also requests that responses for each interrogatory request be provided in separate electronic folders that include the documents responsive to that request.

INTERROGATORIES

1. For this question, please refer to the attached Excel sheet (Attachment PCS-A), which includes information and calculations based on information from DEF witnesses in several prior fuel dockets (Dockets No. 160001-EI, 150001-EI, 140001-EI, 130001-EI, and 120001-EI):

   a. Please confirm that the information in each of the tables included in Attachment PCS-A accurately reflects the data filed by DEF in the indicated past fuel dockets (see above).

   b. If any of the entries are not consistent with the indicated filings, please identify the cell which is incorrect and please provide the correct figure, including an explanation of how that figure was calculated.

/s/ James W. Brew
Stone Mattheis Xenopoulos & Brew, PC
1025 Thomas Jefferson St NW
Eighth Floor, West Tower
Washington, DC 20007
(202) 342-0800
jbrew@smxblaw.com

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF _____)

I hereby certify that on this _____ day of _____, 2016, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared _____, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number(s) _____ from PCS PHOSPHATE'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC (NO. 1) in Docket No(s). 160001-EI, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this _____ day of _____, 2016.

_____
Notary Public
State of Florida, at Large

My Commission Expires:
_____

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 160001-EI DATED: SEPTEMBER 16, 2016

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that PCS PHOSPHATE'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, LLC's (NO. 1) has been served by electronic mail to Matthew Bernier, 106 East College Avenue, Suite 800, Tallahassee, Florida 32301, matthew.bernier@duke-energy.com, and that a true copy thereof has been furnished to the following by electronic mail this 16th day of September, 2016:

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Duke Energy Florida
Peak and Off Peak Comparison
Schedule E1-E, Annual Filings 2012-2016

Estimate for Jan-Dec 2017
Filed 9/1/16, Docket No. 160001-EI
Christopher A. Menendez: Exhibit CAM-3, Part 2

	Peak			Off Peak		
	System load (MWh)	Marginal Cost	Avg. (¢/kWh)	System load (MWh)	Marginal Cost	Avg. (¢/kWh)
Jan-17	873,422	$ 29,224,114	**3.346**	2,375,283	$ 60,017,286	**2.527**
Feb-17	761,550	$ 23,811,466	**3.127**	2,019,184	$ 52,602,764	**2.605**
Mar-17	812,816	$ 23,513,479	**2.893**	2,207,717	$ 60,434,936	**2.737**
Apr-17	983,250	$ 35,599,102	**3.621**	2,087,454	$ 53,609,537	**2.568**
May-17	1,358,300	$ 51,187,028	**3.768**	2,367,439	$ 57,886,049	**2.445**
Jun-17	1,436,913	$ 56,114,917	**3.905**	2,596,108	$ 67,803,584	**2.612**
Jul-17	1,428,381	$ 61,069,925	**4.275**	2,851,812	$ 77,588,407	**2.721**
Aug-17	1,566,184	$ 66,696,607	**4.259**	2,779,608	$ 76,878,153	**2.766**
Sep-17	1,359,081	$ 53,078,141	**3.905**	2,644,013	$ 70,596,811	**2.670**
Oct-17	1,201,154	$ 49,604,752	**4.130**	2,296,150	$ 62,944,463	**2.741**
Nov-17	771,942	$ 20,762,043	**2.690**	2,154,582	$ 57,494,720	**2.668**
Dec-17	827,088	$ 25,666,990	**3.103**	2,365,790	$ 59,160,124	**2.501**
Total/avg	13,380,081	$ 496,328,564	**3.709**	28,745,140	$ 757,016,834	**2.634**

Duke Energy Florida
Peak and Off Peak Comparison
Schedule E1-E, Annual Filings 2012-2016

Estimate for Jan-Dec 2016
Filed 9/1/15, Docket No. 150001-EI
Christopher A. Menendez: Exhibit CAM-3, Part 2

	Peak			Off Peak		
	System load (MWh)	Marginal Cost	Avg. (¢/kWh)	System load (MWh)	Marginal Cost	Avg. (¢/kWh)
Jan-16	796,939	$ 25,857,235	**3.245**	2,406,386	$ 66,812,415	**2.776**
Feb-16	770,139	$ 25,701,963	**3.337**	2,163,223	$ 61,868,642	**2.860**
Mar-16	817,553	$ 26,459,782	**3.236**	2,218,735	$ 66,864,473	**3.014**
Apr-16	1,042,945	$ 43,801,892	**4.200**	2,050,490	$ 54,236,979	**2.645**
May-16	1,300,463	$ 70,342,318	**5.409**	2,398,650	$ 67,602,424	**2.818**
Jun-16	1,442,799	$ 75,455,216	**5.230**	2,641,475	$ 76,017,392	**2.878**
Jul-16	1,398,848	$ 78,548,643	**5.615**	2,888,750	$ 89,849,344	**3.110**
Aug-16	1,569,485	$ 89,934,029	**5.730**	2,785,959	$ 83,533,227	**2.998**
Sep-16	1,410,640	$ 79,567,495	**5.641**	2,613,272	$ 81,631,075	**3.124**
Oct-16	1,147,956	$ 55,244,225	**4.812**	2,380,085	$ 73,642,672	**3.094**
Nov-16	788,686	$ 24,443,299	**3.099**	2,141,576	$ 60,753,378	**2.837**
Dec-16	851,694	$ 29,061,267	**3.412**	2,360,812	$ 65,958,451	**2.794**
Total/avg	13,338,147	$ 624,417,364	**4.681**	29,049,413	$ 848,770,472	**2.922**

Duke Energy Florida
Peak and Off Peak Comparison
Schedule E1-E, Annual Filings 2012-2016

Estimate for Jan-Dec 2015
Filed 8/22/14, Docket No. 140001-EI
Thomas G. Foster: Exhibit TGF-3, Part 2

	Peak			Off Peak		
	System load (MWh)	Marginal Cost	Avg. (¢/kWh)	System load (MWh)	Marginal Cost	Avg. (¢/kWh)
Jan-15	848,405	$ 36,773,208	**4.334**	2,296,121	$ 74,786,984	**3.257**
Feb-15	738,227	$ 34,512,286	**4.675**	2,064,839	$ 71,390,078	**3.457**
Mar-15	770,030	$ 32,571,134	**4.230**	2,153,340	$ 76,932,716	**3.573**
Apr-15	1,077,068	$ 63,994,355	**5.942**	1,968,264	$ 63,780,311	**3.240**
May-15	1,243,861	$ 72,794,652	**5.852**	2,406,613	$ 82,359,441	**3.422**
Jun-15	1,405,702	$ 81,752,678	**5.816**	2,521,153	$ 84,546,503	**3.353**
Jul-15	1,471,948	$ 96,339,873	**6.545**	2,627,310	$ 90,223,688	**3.434**
Aug-15	1,364,647	$ 82,629,098	**6.055**	2,797,685	$ 102,503,512	**3.664**
Sep-15	1,426,454	$ 86,673,653	**6.076**	2,483,906	$ 84,276,951	**3.393**
Oct-15	1,213,054	$ 67,123,022	**5.533**	2,249,444	$ 74,078,928	**3.293**
Nov-15	725,131	$ 29,467,100	**4.064**	2,103,699	$ 75,115,038	**3.571**
Dec-15	881,722	$ 37,629,270	**4.268**	2,216,298	$ 70,667,815	**3.189**
Total/avg	13,166,249	$ 722,260,329	**5.486**	27,888,672	$ 950,661,965	**3.409**

Duke Energy Florida
Peak and Off Peak Comparison
Schedule E1-E, Annual Filings 2012-2016

Estimate for Jan-Dec 2014
Filed 8/30/13, Docket No. 130001-EI
Thomas G. Foster: Exhibit TGF-3, Part 2

	Peak			Off Peak		
	System load (MWh)	Marginal Cost	Avg. (¢/kWh)	System load (MWh)	Marginal Cost	Avg. (¢/kWh)
Jan-14	943,942	$ 38,695,756	**4.099**	2,186,482	$ 69,335,693	**3.171**
Feb-14	746,267	$ 29,976,426	**4.017**	2,008,805	$ 63,980,043	**3.185**
Mar-14	731,189	$ 26,957,363	**3.687**	2,235,527	$ 74,571,902	**3.336**
Apr-14	1,097,848	$ 51,851,964	**4.723**	1,956,957	$ 65,579,300	**3.351**
May-14	1,340,577	$ 100,364,691	**7.487**	2,338,227	$ 84,613,516	**3.619**
Jun-14	1,424,635	$ 71,016,802	**4.985**	2,641,126	$ 91,157,952	**3.451**
Jul-14	1,566,806	$ 80,448,844	**5.135**	2,616,191	$ 89,027,790	**3.403**
Aug-14	1,449,388	$ 90,662,803	**6.255**	2,817,534	$ 97,909,543	**3.475**
Sep-14	1,448,413	$ 77,758,876	**5.369**	2,482,395	$ 80,573,739	**3.246**
Oct-14	1,238,447	$ 65,930,950	**5.324**	2,078,761	$ 74,688,432	**3.593**
Nov-14	661,446	$ 23,903,790	**3.614**	2,169,550	$ 77,422,505	**3.569**
Dec-14	892,102	$ 33,978,468	**3.809**	2,192,000	$ 71,830,000	**3.277**
Total/avg	13,541,060	$ 691,546,733	**5.107**	27,723,555	$ 940,690,415	**3.393**

Duke Energy Florida
Peak and Off Peak Comparison
Schedule E1-E, Annual Filings 2012-2016

Estimate for Jan-Dec 2013
Filed 8/31/12, Docket No. 120001-EI
Marcia Oliver: Exhibit MO-2, Part 2

	Peak			Off Peak		
	System load (MWh)	Marginal Cost	Avg. (¢/kWh)	System load (MWh)	Marginal Cost	Avg. (¢/kWh)
Jan-13	908,507	$ 34,308,941	**3.776**	2,175,156	$ 59,927,218	**2.755**
Feb-13	737,900	$ 26,074,527	**3.534**	1,988,862	$ 56,704,320	**2.851**
Mar-13	750,484	$ 28,614,525	**3.813**	2,272,021	$ 79,954,155	**3.519**
Apr-13	1,066,284	$ 66,368,419	**6.224**	1,977,884	$ 65,176,120	**3.295**
May-13	1,385,640	$ 94,691,394	**6.834**	2,337,336	$ 75,945,313	**3.249**
Jun-13	1,311,997	$ 84,803,959	**6.464**	2,652,018	$ 85,606,498	**3.228**
Jul-13	1,532,063	$ 105,284,682	**6.872**	2,632,028	$ 89,962,639	**3.418**
Aug-13	1,486,147	$ 104,711,651	**7.046**	2,754,487	$ 92,421,724	**3.355**
Sep-13	1,357,718	$ 86,495,030	**6.371**	2,523,508	$ 79,217,651	**3.139**
Oct-13	1,241,223	$ 56,403,182	**4.544**	2,134,164	$ 65,213,226	**3.056**
Nov-13	692,683	$ 20,006,458	**2.888**	2,114,632	$ 59,526,736	**2.815**
Dec-13	808,679	$ 27,384,728	**3.386**	2,253,619	$ 65,198,428	**2.893**
Total/avg	13,279,325	$ 735,147,496	**5.536**	27,815,715	$ 874,854,028	**3.145**